



ERNEST ORLANDO LAWRENCE BERKELEY NATIONAL LABORATORY

Estimating Demand Response Market Potential among Large Commercial and Industrial Customers: A Scoping Study

Charles Goldman, Nicole Hopper, and Ranjit Bharvirkar
Lawrence Berkeley National Laboratory

Bernie Neenan and Peter Cappers
Utilipoint International

**Environmental Energy
Technologies Division**

January 2007

The work described in this report was funded by the Permitting, Siting and Analysis Division of the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.

Disclaimer

This document was prepared as an account of work sponsored by the United States Government. While this document is believed to contain correct information, neither the United States Government nor any agency thereof, nor The Regents of the University of California, nor any of their employees, makes any warranty, express or implied, or assumes any legal responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by its trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or The Regents of the University of California. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

Ernest Orlando Lawrence Berkeley National Laboratory is an equal opportunity employer.

Estimating Demand Response Market Potential among Large
Commercial and Industrial Customers:
A Scoping Study

Prepared for
Office of Electricity Delivery and Energy Reliability
U.S. Department of Energy

Principal Authors:

Charles Goldman, Nicole Hopper and Ranjit Bhavirkar
Lawrence Berkeley National Laboratory

Bernie Neenan and Peter Cappers
Utilipoint International

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

January 2007

The work described in this report was funded by the Permitting, Siting and Analysis Division of the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.

Acknowledgements

The work described in this report was funded by the Permitting, Siting and Analysis Division of the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.

We thank Richard Sedano (Regulatory Assistance Project), Hossein Haeri (Quantec LLC), Steven Braithwait (Christensen Associates), Roger Levy and Mary Ann Piette (Demand Response Research Center), Larry Mansueti (DOE), Joe Eto (Lawrence Berkeley National Laboratory) and Dan Engel (FSC Group) for their comments on a draft of this report. We also acknowledge Henry Yoshimura (ISO-New England), Michael Kelliher, Catherine McDonough and Art Hamlin (National Grid), Dave Lawrence (NYISO), Mike Gravely (CEC) and Mike Rufo (Itron) for providing the data and information used in this study.

Table of Contents

Acknowledgements	i
Table of Contents	ii
List of Figures	iii
List of Tables	iv
Acronyms and Abbreviations	v
Executive Summary	vii
1. Introduction	1
2. Methods and Concepts for Estimating Demand Response Market Potential	5
2.1 What is Market Potential?	5
2.2 Approaches Used to Study Demand Response Market Potential	7
2.3 What Makes Demand Response Different from Energy Efficiency?	9
2.4 A Different Approach to Demand Response Market Potential for Large Customers	11
3. A Framework for Estimating Large Customer Demand Response Market Potential	13
3.1 Establishing the Study Scope	13
3.2 Customer Segmentation	15
3.3 Estimating Net Program Penetration Rates	15
3.4 Estimating Price Response	19
3.4.1 Selecting a Measure of Price Response	19
3.4.2 Calculating Elasticity Values	23
3.4.3 Accounting for Factors that Influence Price Response	23
3.5 Estimating Load Impacts	25
3.5.1 Estimating Load Impacts from Arc Elasticities	26
3.5.2 Estimating Load Impacts from Substitution Elasticities	26
4. Applying the Framework: Large Customer Demand Response Market Potential	27
4.1 Data Sources	29
4.2 Estimating Program Participation from Large Customer Program Experience	29
4.3 Developing Elasticity Values and Adjustment Factors from Large Customer Response Data	32
4.3.1 Average Elasticity Values	32
4.3.2 Elasticities Adjusted for Onsite Generation	32
4.3.3 Elasticities Refined to Reflect Response at High Prices	34
4.3.4 Elasticities Refined for Within-Sector Variation in Price Response	36
4.4 Putting it All Together: Market Potential Simulation Results	37
4.4.1 Base Case	39
4.4.2 Impact of Participation Rates	39
4.4.3 Accounting for Onsite Generation	40
4.4.4 Accounting for Response at High Prices	41
4.4.5 Accounting for Within-Sector Variations in Customer Response	42
4.5 Summary: Discussion	43
5. Advancing the State of the Art: A Market Assessment Research Agenda	45
References	49
Appendix A. Review of Methods for Estimating Demand Response Potential	53
Appendix B. Methods for Establishing Customer Baseline Loads	61
Appendix C. Programs and Tariffs Used as Data Sources	63
Appendix D. Factors Found to Influence Demand Response Program Participation	67

List of Figures

Executive Summary:

Figure ES-1. Impact of Program Participation Rates on Demand Response Market Potentials	xiii
-----------------------------------------------------------------------------------------------	------

Report:

Figure 2-1. Relative Relationships of Energy-Efficiency Potential Definitions.....	6
Figure 3-1. Steps for Estimating Demand Response Market Potential	14
Figure 3-2. Features of Price Elasticity Measures	20
Figure 4-1. Impact of Program Participation Rates on Demand Response Market Potentials	40

List of Tables

Executive Summary:

Table ES-1. Data Sources	xi
Table ES-2. Average Elasticity Values.....	xi
Table ES-3. Market Potential Results: Base Case	xii

Report:

Table 3-1. Methods of Estimating Demand Response Penetration Rates	17
Table 3-2. Factors that May Influence Demand Response	24
Table 4-1. Demand Response Options Included in Market Potential Simulation	28
Table 4-2. Data Sources	29
Table 4-3. Participation Rates in Demand Response Programs and Dynamic Pricing Tariffs	31
Table 4-4. Average Elasticity Values	33
Table 4-5. Availability of Data on External and Customer-Specific Factors	33
Table 4-6. Elasticity Values Adjusted for Onsite Generation.....	34
Table 4-7. Elasticities Based on Customer Response to High Prices (\$500/MWh)	35
Table 4-8. Low, Medium and High Elasticity Seed Values	37
Table 4-9. Prices Used in Market Potential Simulations	38
Table 4-10. Market Potential Results: Base Case	39
Table 4-11. Market Potential Results: Onsite Generation	41
Table 4-12. Market Potential Results: Response at High Prices	42
Table 4-13. Market Potential Results: Response Distribution Effects	43

Appendices:

Table D-1. Churn Rates for ISO-NE and NYISO Demand Response Programs	68
----------------------------------------------------------------------------	----

Acronyms and Abbreviations

C&I	commercial and industrial (utility customers)
CBL	customer baseline load
DOE	(U.S.) Department of Energy
DR	demand response
EDRP	Emergency Demand Response Program
EPACT	Energy Policy Act (of 2005)
ISO-NE	ISO-New England
ISO	Independent System Operator
kW	kilowatt
kWh	kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
NMPC	Niagara Mohawk Power Corporation (a National Grid company)
NYISO	New York Independent System Operator
RTO	Regional Transmission Organization
RTP	real-time pricing

Executive Summary

Demand response is increasingly recognized as an essential ingredient to well functioning electricity markets. This growing consensus was formalized in the Energy Policy Act of 2005 (EPACT), which established demand response as an official policy of the U.S. government, and directed states (and their electric utilities) to consider implementing demand response, with a particular focus on “price-based” mechanisms.¹ The resulting deliberations, along with a variety of state and regional demand response initiatives, are raising important policy questions: for example, *How much demand response is enough? How much is available? From what sources? At what cost?*

The purpose of this scoping study is to examine analytical techniques and data sources to support demand response market assessments that can, in turn, answer the second and third of these questions. We focus on demand response for large (> 350 kW), commercial and industrial (C&I) customers, although many of the concepts could equally be applied to similar programs and tariffs for small commercial and residential customers.²

A number of utilities and regional groups have performed demand response market potential studies in recent years.³ Such studies have been conducted primarily to develop the demand-side section of utility resource plans, or to assist with planning or screening of potential demand response programs. Going forward, in addition to these motivations, we anticipate that market assessments may be useful to utilities and state policymakers in their response to EPACT, as a means to help determine the feasibility of various demand response options in their service territories. Additionally, some states and regions have begun to set demand response goals⁴; market assessment studies could serve as a foundation to ensure that such goals are achievable, and help identify market segments and strategies to meet them.

In this scoping study, we review analytical methods and data that can support market assessments (e.g., for dynamic pricing tariffs) or market potential studies (e.g., for programmatic demand response) that can support these functions. We present a conceptual framework for estimating market potential for large customer demand response, compile participation rates and elasticity values from six large customer dynamic pricing and demand response programs and apply them to estimate demand response market potential in an illustrative utility service territory. Finally, we present a research agenda that identifies additional information and improved methods that would support more reliable demand response market assessments.

¹ Energy Policy Act of 2005, Section 1252(b).

² Our proposed approach may not be appropriate for direct load control programs, which are widespread demand response approaches offered to small commercial and residential customers (see section 2.2).

³ See Haeri and Gage (2006), Quantum Consulting and Summit Blue Consulting (2004), SCE (2003), and EPRI Solutions (2005).

⁴ For example, the California Public Utilities Commission (CPUC) has set demand response goals for the state’s investor-owned utilities (CPUC 2004 and 2006b) and the Northwest Power and Conservation Council proposed a regional goal of 500 MW of demand response in its 5th Power Plan (NPCC 2005).

What is Demand Response Market Potential?

Demand response market potential is *the amount of demand response—measured as short-term load reductions in response to high prices or incentive payment offerings—that policymakers can expect to achieve by offering a particular set of demand response options to customers in a particular market or market segment under expected market or operating conditions.*⁵

In this report, we use the terms “market potential” and “market assessment” interchangeably. *Market potential* studies are typically undertaken by policymakers to determine the achievable market penetration, benefits, and costs of a policy or program (such as a ratepayer-funded energy efficiency program). In assessing the merits of dynamic pricing *tariffs*, policymakers may nonetheless be interested in many of the same issues addressed by a market potential study—customer acceptance rates, level of price response, etc.—and often will conduct *market assessments* to forecast likely market penetration (and electric sales and revenues) in cases where customers can choose among several tariffs. The methods discussed in this report are equally applicable to both market potential studies of demand response programs and market assessments of dynamic pricing tariffs.

Approaches Used to Study Demand Response Market Potential

Studies of demand response market potential necessarily involve estimating two separate elements: *participation*, the number of customers enrolling in programs or taking service on a dynamic pricing tariff; and *response*, quantities of load reductions at times of high prices or when curtailment incentives are offered. Among seven reviewed demand response market potential studies⁶, four distinct approaches were used:

- *Customer surveys*—Participation rates and expected load curtailments are obtained from surveys of utility customers about their expected actions if offered hypothetical demand response options and used to estimate market potential.
- *Benchmarking*—Participation rates and load reductions observed among customers in other jurisdictions are applied to the population of interest.
- *Engineering approach*—Four of the seven reviewed studies used bottom-up engineering techniques, similar to those used to estimate energy efficiency market potential. All are variations on the approach of applying assumed participation and response rates to data on local customers, loads or equipment stock.
- *Elasticity approach*—This approach involves estimating price elasticities from the usage data of customers exposed to demand response programs and/or dynamic pricing tariffs. After determining an expected participation level, price elasticities are applied to the population of interest to estimate load impacts under an expected range of prices or level of financial incentives to curtail load.

⁵ It can be expressed as a percentage reduction in market demand that can be expected at, for example, a price (or offered curtailment incentive) of \$500/MWh.

⁶ See Appendix A for a summary of the reviewed studies.

What Makes Demand Response Different from Energy Efficiency?

While energy efficiency and demand response both involve modifying large customers' use of and demand for electricity, they differ in the following important ways:

- *The nature of participation*—For demand response options, participation involves two steps: enrolling in a program or tariff, usually on an annual (or other periodic) basis; and providing load reductions during specific events (e.g., system emergencies or periods of high prices). For energy efficiency, “participation” consists of a one-time decision to invest in energy-efficiency measures or equipment.
- *The drivers of benefits*—Demand-response benefits often hinge on customer behavior (i.e., ability and willingness to curtail) in response to hourly prices, financial incentives, and/or system emergencies. Energy efficiency savings are largely a function of the technical characteristics and performance of the installed equipment or measures.
- *The time horizon and valuation of benefits*—From a customer perspective, demand-response benefit streams may be highly variable and are often short-term. For example, customers on hourly or critical-peak pricing can save on their utility bills by shifting or curtailing load in response to peak and off-peak prices. They can also receive incentive payments for emergency demand response program events, but these tend to be relatively infrequent. In contrast, investments in energy efficiency measures typically produce a fairly certain stream of savings over a multi-year period (i.e. the economic lifetime of the measure) which the customer can value at expected retail energy rates.

A Framework for Estimating Large Customer Demand Response Market Potential

For large customer demand response options, that rely on customer-initiated response to prices (e.g. hourly or critical-peak pricing) or curtailment incentives (e.g. short-notice emergency program, price response event program), we recommend an elasticity approach for estimating load reductions in market potential studies. The elasticity approach explicitly links response to prices and customer behavior. When demand models are used to estimate elasticities, they also enable the translation of experience from other jurisdictions with adjustments for differences in customer- and market-specific factors.⁷

We propose a framework for estimating large customer demand response market potential in a given jurisdiction or utility service territory that involves five steps:

- *Establishing the study scope*—identifying the target population and types of demand response options to be considered;

⁷ For direct load control (DLC) programs, which are commonly offered to small commercial and residential customers, bottom-up engineering approaches are appropriate; these methods are commonly used to estimate energy efficiency potential.

- *Customer segmentation*—identifying “customer market segments” (groups of customers with similar characteristics that are expected to respond in similar ways) among the target population;
- *Estimating net program penetration rates*—using available data to estimate customer enrollment in voluntary programs and customer exposure to default pricing programs; participation is often the most difficult aspect of demand response options to estimate at present due to a limited experience base;
- *Estimating price response*—selecting an appropriate measure of price response (price elasticity of demand, substitution elasticity or arc elasticity) given available data, and developing elasticity estimates for various demand response options, customer market segments, and factors found to influence price response from the observed load response of customers exposed to demand response options; and
- *Estimating load impacts*—combining the above steps to estimate the expected demand response that can be expected from the target population at a reference price.

Applying the Framework: Large Customer Demand Response Market Potential

We applied the above framework, using available data on large customer participation and response, to estimate the market potential of several types of demand response programs and dynamic pricing tariffs at an illustrative urban utility.

We limited our analysis to large, non-residential customers with peak demand greater than 350 kW and examined five different types of demand response option.⁸ We developed separate data inputs and results for five market segments: manufacturing, government/education, commercial/retail, healthcare, and public works.

Data Sources and Simulation Inputs

We gathered data from six demand response programs and dynamic pricing tariffs offered to large commercial and industrial customers by utilities and regional grid operators in recent years (see Table ES-1).

We compiled participation rates by market segment and customer size for each demand response option. Our goal was to gather data on program participation based on relatively mature programs with 3–4 years of operation. Where possible, we used actual program participation data from the data sources in Table ES-1. We filled in gaps by surveying program managers of similar programs and tariffs, and inferring data from other market segments or programs.

⁸ We only had access to individual customer level data from several large-customer demand response options, which facilitated estimation of participation rates and customer response for large customers, but not smaller commercial or residential customers. We analyzed these options *independently* and did not account for possible interactions between different options should they be offered simultaneously to a given set of customers. Program designers that intend to offer a variety of demand response options should ensure that such interactions are accounted for in market potential studies

Table ES-1. Data Sources

DR Option	Data Source(s)	Eligible Customers (peak demand)
Optional hourly pricing	Central and Southwest (CSW) Utilities' (now American Electric Power) two-part RTP rate	<1500 kW
Default hourly pricing	Niagara Mohawk Power Corporation (NMPC), a National Grid Company, SC-3A tariff	> 2000 kW
Short-notice emergency program	NYISO Emergency Demand Response Program (EDRP)	> 100 kW
	ISO-NE Real-Time Demand Response (RTDR) Program	> 100 kW
Price-response event program	ISO-NE Real-Time Price Response (RTPR) Program	> 100 kW
Critical-peak pricing	California Utilities ¹ Critical Peak Pricing Program	> 200 kW; > 100 kW for SDG&E

¹ Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E)

We also calculated elasticity values for each demand response option, disaggregated by market segment, using individual customer load and price data. For the two hourly pricing tariffs, we estimated demand models to calculate *substitution elasticities*. For the other programs, insufficient numbers of observations covering too small a range of prices were available to estimate a fully specified demand model, so we calculated *arc elasticities* instead.⁹

The average elasticity values estimated for each program and market segment are presented in Table ES-2. For some of our market potential scenarios, we refined these average elasticity estimates to reveal differences in customer response associated with onsite generation ownership, high prices, and variations in responsiveness within market segments.

Table ES-2. Average Elasticity Values

Customer Market Segment	Demand Response Option				
	Optional Hourly Pricing	Default Hourly Pricing	Short-notice Emergency Program	Price Response Event Program	Critical-peak Pricing
Commercial/retail	0.01	0.06	-0.03	-0.09	-0.10
Government/education	0.01	0.10	-0.02	-0.16	-0.06
Healthcare	0.01	0.04	-0.04	-0.05	-0.01
Manufacturing	0.26	0.16	-0.04	-0.16	-0.05
Public works	0.07	0.02	-0.08	-0.22	-0.08

Note: Elasticity of substitution values are shown for optional and default hourly pricing and are typically positive; arc elasticity values are shown for all other demand response options and are typically negative.

⁹ See section 3.4.1 for a discussion of various elasticity measures. Substitution-elasticity and arc-elasticity values are not directly comparable, although the market potential impacts derived from them are.

Market Potential Simulations

We applied the elasticity values to information on the customer population of an urban utility in the Northeastern U.S. (see the adjacent textbox) to develop market potential estimates. We also analyzed several alternative scenarios to demonstrate the effects of various factors on demand response market potential. We highlight a selection of the results here.

Base Case

The overall base-case results range from 0% to 3% of the peak demand of the target population of customers larger than 350 kW (see Table ES-3). The load reductions for the largest customers (>1 MW) enrolled in the default hourly pricing and price response event programs represent 5-6% of their aggregate peak demand. The highest market potential (3% of peak demand) corresponds to the default hourly pricing tariff—this is largely due to relatively high customer acceptance rates for this tariff.

Overview of our Sample Utility

We selected an urban utility in the Northeastern U.S., for which we had access to large customer characteristics and usage data, to demonstrate market potential simulations.

The selected utility is relatively small; the peak demand of its large, non-residential customers is only ~1,700 MW. These customers represent about 40% of the utility's peak demand, and consist largely of commercial/retail, government/education and healthcare facilities. Manufacturing customers are less prevalent than for utilities that serve suburban or rural communities.

Table ES-3. Market Potential Results: Base Case

Customer Size (MW)	Optional Hourly Pricing		Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
	MW	% of class peak demand ¹	MW	% of class peak demand ¹	MW	% of class peak demand ¹	MW	% of class peak demand ¹	MW	% of class peak demand ¹
0.35–0.5	1.0	0%	2.8	0%	0.4	0%	1.6	0%	1.3	0%
0.5–1	1.1	0%	3.9	1%	4.3	1%	3.0	1%	1.7	1%
1–2	1.9	1%	14.4	6%	3.8	2%	3.9	2%	1.9	1%
> 2	21.6	4%	34.8	6%	11.5	2%	29.1	5%	2.4	0%
Total	25.6	2%	55.9	3%	19.9	1%	37.6	2%	7.3	0%

¹ Peak demand is non-coincident.

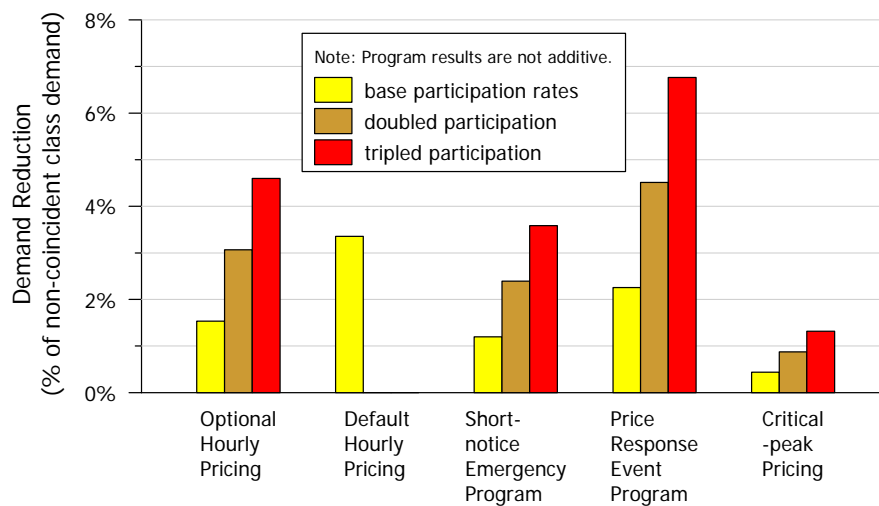
Note: Each demand response option was evaluated separately—the results are not additive.

Impact of Program Participation Rates

Market assessments often examine the impact of differing rates of participation on program potential. Figure ES-1 illustrates the impact of aggressively marketing programs or promoting optional tariffs to achieve two and three times the base-case participation rates, which reflect current demand response experience. The results, on the order of 3–6 percent of non-residential peak demand, can be viewed as an approximate upper bound on demand response potentials.¹⁰ For default hourly pricing, which by definition would

¹⁰ These results assume that the additional enrolled customers are just as responsive to price signals or emergencies as the relatively “early adopters” observed among our data sources. In reality, it may be that

not be marketed to customers, we do not show enhanced participation, although the base case results are included in the figure for comparison.



Note: The level of demand response (elasticity) is assumed to be the same for all scenarios—this assumption has yet to be evaluated with actual program experience.

Figure ES-1. Impact of Program Participation Rates on Demand Response Market Potentials

Accounting for Onsite Generation

We examined the impact of refining the elasticity estimates for the short-notice emergency program to account for differences in response by customers with and without onsite generation technology.¹¹ On average, customers in this demand response program with onsite generators had arc elasticities about 40% higher than customers that did not. This translates to elasticity values for customers without onsite generation that are 14% lower than the average elasticities for each market segment. For those with onsite generation, the elasticity values are 52% higher than the average.

Applying these refined and more disaggregated elasticity estimates to the population of customers in our illustrative utility resulted in slightly lower market potential estimates than the base case for this demand response option (i.e., 17.6 versus 19.9 MW). This is due to differences in our assumptions about the distribution of onsite generators among

the most responsive customers are also the first to sign up, leading to declining average elasticities as more customers are enrolled. On the other hand, strategies that combine program marketing with technical assistance to develop fully automated demand response could enhance both participation rates and response to prices or emergencies. An automated demand response pilot in California with a sample of ~30 medium and large commercial, institutional, and high-tech buildings demonstrated this potential, achieving consistent average load curtailments of ~10% with high customer satisfaction (Piette et al. 2005). California's investor-owned utilities will be ramping up automated demand response in 2007-08 to several hundred facilities (CPUC 2006a).

¹¹ Data were not available on the presence of onsite generation among customers in the other demand response options.

the customer population at the illustrative urban utility compared to the observed distribution among the customers from whom the elasticity estimates were estimated.

Summary: Discussion

The results of our simulations illustrate possible ranges of demand response market potential for large commercial and industrial customers at an urban Northeast utility, as well as several key methodological and data issues. The results are specifically tied to the characteristics of this urban utility's large customer base as well as the specific assumptions we made about prices and other factors in the various scenarios.

Nonetheless, we draw the following insights and conclusions from our scoping study of demand response market potential:

- We believe that the results provide a **reasonable first approximation of the range of demand response market potential among non-residential customers** if offered similar demand response options by similar utilities. The aggregate load reductions for our urban, northeast utility ranged from less than 1% to 3% of the peak demand of the target population of large customers. While these load reductions are modest, a number of studies suggest that a little demand response can often go a long way towards ameliorating system emergencies or high prices. If policymakers or regulators establish higher demand response goals (e.g. California's goal of 5% of price-responsive load), then our results suggest that the demand response market potential of all customer classes should be considered—not just the large commercial and industrial customers included in this study. Pilot program results suggest that enabling technologies and automated demand response can also increase both the number of customers willing to participate in demand response options as well as the predictability and consistency of their load response.
- The simulations illustrate the **relative impact of certain factors, particularly customer participation rates, on potential aggregate load reductions** of large customers. Participation rates currently represent the largest data uncertainty for analysts undertaking market potential studies. Yet achieving higher participation rates among eligible large customers is critical for obtaining a significant amount of price-responsive load. Any assessment of demand response potential can not ignore the level of program resources that will be devoted to its implementation.
- The scenarios also demonstrate **the importance of refining elasticity estimates rather than applying average values**. In several cases, this resulted in *lower* market potential estimates in our simulations. Policymakers considering establishing demand response goals would be well advised to be cautious, as goals extrapolated from pilot programs or demand response potential study estimates based only on small samples of very responsive customers may not be achievable.
- Finally, we emphasize that **all demand response market potential studies should examine a range of scenarios**—not necessarily limited to those demonstrated here—in estimating the potential of demand response options to deliver load reductions when needed.

Advancing the State of the Art: A Market Assessment Research Agenda

To advance the state of knowledge about customer response to demand response programs and dynamic pricing tariffs, and facilitate demand response market assessments, we recommend that state and federal policymakers and regulators encourage utilities, other load serving entities, Independent System Operators/Regional Transmission Organizations, program evaluators and analysts to conduct the following activities:

1. **Link Program Evaluation to Market Potential Studies:** Evaluations of demand response programs should systematically collect data on the characteristics of participating customers; hourly customer loads, prices and response; other factors found to be relevant drivers of customer participation and response; and information on the size and characteristics of the target or eligible population.
2. **Program Participation:** Develop predictive methods for estimating participation rates in demand response programs and dynamic pricing tariffs that incorporate customer characteristics and other factors that drive participation. Where applicable, studies should include interactive effects of multiple program offerings in estimating market penetration rates.
3. **Price Response:** Estimate price elasticity values for different market segments, accounting for the relative impact of driving factors, and report methods and results transparently. Where possible, we recommend that provisions be made to estimate demand or substitution elasticities, using fully specified demand models, rather than arc elasticities.
4. **Assess the Impacts of Demand Response Enabling Technologies:** *For large customers, there is still a need to document the impacts of specific demand response enabling technologies on customer participation and load response, given limited evidence and mixed results from existing evaluations. At a minimum, program evaluators should gather information on customer's load curtailment strategies that involve onsite generation,¹² peak load controls, energy management control systems, energy information systems, and any other technologies disseminated as part of technical assistance programs.*
5. **Publicize Results:** *Explore ways to pool customer-level data, while protecting customer confidentiality, so that information to support demand response market assessments is available in a standardized format.*

¹² Information on diesel-fired emergency back-up generators should be tracked separately from cogeneration, combined heat and power, and other distributed energy technologies.

1. Introduction

Demand response is increasingly recognized as an essential ingredient to well functioning electricity markets, both in the context of organized wholesale markets and more traditional market structures. This growing consensus was formalized in the Energy Policy Act (EPACT) of 2005, which states that it is the policy of the United States to encourage time-based pricing and other forms of demand response. The legislation also charges state regulatory authorities with conducting investigations to determine whether to adopt widespread time-based pricing and advanced metering for retail customers of electric utilities.¹³ The resulting deliberations, along with a variety of state and regional demand response initiatives, are raising important policy questions: for example, *How much demand response is enough? How much is available? From what sources? At what cost?*

The purpose of this scoping study is to examine analytical techniques and data sources to support demand response market assessments that can, in turn, answer some of these questions. We focus on demand response for large (> 350 kW), commercial and industrial (C&I) customers, although many of the concepts could equally be applied to similar programs and tariffs for small commercial and residential customers.¹⁴

The U.S. Department of Energy (DOE) defines demand response as:

changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized (DOE 2006).

Customers can be induced to provide demand response either through *dynamic pricing tariffs*—retail electric rates that reflect short-term changes in wholesale electricity costs (e.g., hourly pricing or critical-peak pricing)—or *demand response programs* that offer customers payments in return for reducing consumption when called upon to mitigate high market prices or reserve shortfalls.¹⁵

Among large C&I customers, recent evaluations of demand response programs offered by Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs) and case studies of dynamic pricing tariffs (e.g., Niagara Mohawk, a National Grid Company, Central and Southwest Services, Duke Power, Georgia Power) provide information on observed customer adoption rates and levels of demand response.¹⁶ For

¹³ Energy Policy Act of 2005, Section 1252(b).

¹⁴ Our proposed approach may not be appropriate for direct load control programs, which are widespread demand response approaches offered to small commercial and residential customers (see section 2.2).

¹⁵ Customer response to these two types of demand response option can be thought of as *price-responsive demand* (for dynamic pricing tariffs and price-triggered programs), and *emergency demand response* (for programs designed to mitigate shortfalls in system reserves and reduce the likelihood of rotating outages).

¹⁶ For example, demand response program evaluations have been conducted for NYISO (Neenan et al. 2002 and 2003) and ISO-NE (RLW Analytics and Neenan Associates 2003, 2004 and 2005). Case studies of large customer dynamic pricing have been conducted for the following utilities' programs: Niagara

small customers, a larger body of information is available on response to direct load control programs,¹⁷ and several critical-peak pricing pilots have published results¹⁸ or are in progress (e.g., PSEG, Washington DC). These studies of large customer and mass market demand response provide insights into customer acceptance of and response to a variety of demand response offerings, although their results are typically not sufficiently disaggregated to apply them to market assessments in other jurisdictions.

A number of utilities and regional groups have performed demand response market potential studies in recent years.¹⁹ Such studies have been conducted primarily in two contexts: to develop the demand-side section of a utility's integrated resource plan, and to assist with planning or screening of potential demand response programs (Gunn 2005).²⁰

Going forward, we anticipate that market assessments may also be useful to utilities and state policymakers in their response to EPACT, as a means to help determine the feasibility of various demand response options in their service territories. Finally, a few states and regions have begun to set or consider demand response goals²¹; market assessment studies could serve as a foundation to ensure that such goals are achievable, and help identify market segments and strategies to meet them.

In these contexts, a number of policy questions arise, some of which we address in this study, and others not. Chief among them are:

- **What is the value of demand response?** A recent DOE study developed an analytic framework for assessing the net benefits of demand response and conducted a comparative analysis of existing studies of demand response benefits (DOE 2006). We do not address this question in this report.
- **How much demand response is enough (or needed)?** There is currently no consensus on this issue, and this study does not address it. We note that the answer depends in part on which policy goals motivate the question (e.g., enhancing wholesale market competition, mitigating high energy prices, avoiding rolling blackouts, or deferring the need to build new peaking generation or distribution system infrastructure).

Mohawk, a National Grid Company (Goldman et al. 2005), Central and Southwest Services (Boisvert et al. 2004), Duke Power (Schwarz et al. 2002), and Georgia Power (Braithwait and O'Shealy 2001).

¹⁷ Section 4 of DOE (2006) summarizes the results of these small-customer demand response evaluations.

¹⁸ For example, see California's Statewide Pricing Pilot results (Charles River Associates 2005) and Ameren's Critical Peak Pricing Pilot results (Voytas 2006).

¹⁹ See Haeri and Gage (2006), Quantum Consulting (2004), SCE (2003), and EPRI Solutions (2005).

²⁰ Gunn (2006) also cites contributing to the certificate of need for new generating plants as another motivation for undertaking demand response market potential studies; however, we are unaware of any such examples.

²¹ For example, the California Public Utilities Commission (CPUC) has set demand response goals for the state's investor-owned utilities (CPUC 2004 and 2006b), and the Northwest Power and Conservation Council proposed a regional goal of 500 MW of demand response in its 5th Power Plan (NPCC 2005).

- How much demand response is available? From which customer market segments? From which strategies (e.g., hourly pricing, emergency programs, economic programs, etc.)? These are the primary questions addressed by demand response market assessments. This report focuses on methods and data to answer them.
- **At what cost can demand response be obtained?** Although this question is often addressed by market potential studies or as part of resource planning processes that involve comparing the size and costs of various resources, it is out of the scope of this study. This is in large part because costs are highly situation-specific.²²

In this scoping study, we review methods for addressing the third question above through market assessments or market potential studies. Our approach is as follows:

- we review and compare methods and concepts for estimating demand response and energy efficiency market potential (section 2 of this report);
- we present a conceptual framework and explore methods and tools for estimating large customer demand response market potential that account for customer behavior and prices through the use of price elasticities (section 3);
- we compile participation rates and elasticity values from six large customer dynamic pricing and demand response programs and apply them to estimate demand response market potential in an illustrative utility service territory (chapter 4); and
- we present a research agenda that identifies additional information and improved methods that would support more reliable demand response market assessments (section 5).

Market Potential and Market Assessment

We use the terms “market potential” and “market assessment” somewhat loosely and interchangeably in this report.

Market potential studies are typically undertaken by policymakers to determine the achievable market penetration, benefits, and costs of a policy or program (such as a ratepayer-funded energy efficiency program). For demand response programs that involve incentive payments to participating customers, policymakers may wish to undertake market potential studies.

For dynamic pricing tariffs, policymakers may nonetheless be interested in many of the same issues addressed by a market potential study—customer acceptance rates, level of price response, etc. *Market assessments* fulfill much the same role.

The methods discussed in this report are equally applicable to both market potential studies of demand response programs and market assessments of dynamic pricing tariffs.

²² See DOE (2006) for a description of the types of costs that need to be accounted for in assessing demand response programs.

2. Methods and Concepts for Estimating Demand Response Market Potential

As interest in demand response has grown in recent years, a number of analysts have endeavored to estimate demand response market potential and/or develop methods and tools for doing so. However, their numbers are few and, as Gunn (2005) observes, their methods have not been well vetted.

We began this scoping study with a literature review of seven recent studies and tools designed to estimate demand response market potential.²³ These studies (and tools) and their methodologies are detailed in Appendix A; in this section, we draw from this literature review to discuss methods for estimating demand response market potential. First, we frame the discussion by defining market potential, in the context of both energy efficiency—for which methods and concepts are well vetted—and demand response. We then summarize the approaches used in the reviewed studies. Since most of these studies have adapted methods used to estimate energy-efficiency potential, we identify fundamental differences between energy efficiency and demand response, and from this discussion introduce and make the case for our recommended methodology for demand response options offered to large, non-residential customers.

2.1 What is Market Potential?

Put simply, demand response market potential is *the amount of demand response—measured as short-term load reductions in response to high prices or incentive payment offerings—that policymakers can expect to achieve by offering a particular set of demand response options to customers in a particular market or market segment under expected market or operating conditions.*²⁴

To delve deeper into this question, it is useful to examine the concept of market potential as it is applied to energy efficiency programs or activities. Energy efficiency has a number of similarities to demand response. Both involve affecting customers' usage of or demand for energy. From a resource perspective, both are demand-side resources (DSM) that can defer the need to build new energy supply, transmission or delivery infrastructure. Energy efficiency and demand response are, therefore, often classified along a spectrum of demand-side management strategies.

Energy efficiency potential studies, like energy efficiency programs, have a long history spanning almost three decades, and the motivations, methodologies and definitions of efficiency potential have evolved over this time.

Initially, analysts estimated the *technical potential* for energy efficiency in order to demonstrate to policymakers that savings from a large number of investments in end use equipment could add up to a large aggregate resource. Technical savings potential was

²³ We were aware of a few additional studies, but were unable to obtain enough information to include them (see Appendix A).

²⁴ Demand response market potential can be expressed as a percentage reduction in market demand that can be expected at a given price or offered curtailment incentive (e.g., \$500/MWh).

typically defined as the complete penetration of all energy efficiency measures that were technically feasible (Rufo and Coito 2002). Technical potential was typically estimated using a bottom-up, end use approach—ex ante engineering estimates of savings from replacing the existing stock of equipment and appliances in buildings with high-efficiency options, where feasible and applicable, were applied to information about the distribution of energy-using equipment in the population.

Over time, energy efficiency potential studies evolved to answer questions about the cost of acquiring energy efficiency resources, to estimate the size of resources that could be acquired at less than the cost of new supply infrastructure, and to establish goals. This required estimating *economic potential*, that subset of the technical potential that is cost-effective to implement (given reasonable assumptions about the incremental costs of energy efficiency measures and savings from measures). Over time, this was further refined to estimate *market potential*, the subset of economic potential that is deemed achievable, taking into account factors such as customer cost-effectiveness criteria, awareness, willingness to adopt (which is influenced by various market barriers) and assumed levels of program incentives and activity (Rufo and Coito 2002).²⁵ The relationship of these three concepts is shown in Figure 2-1.

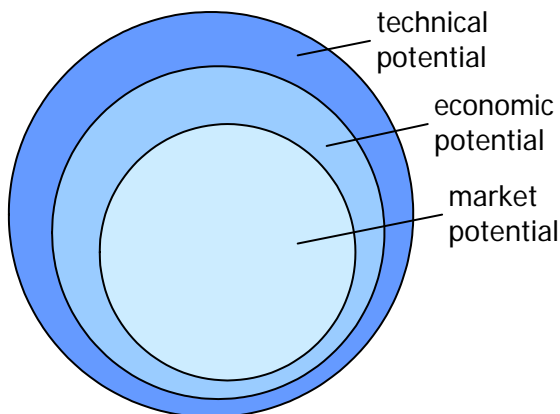


Figure 2-1. Relative Relationships of Energy-Efficiency Potential Definitions

Although economic and market potential studies incorporate economic (e.g., costs and economic savings) and market (e.g., assumed uptake rates) as well as technical factors (e.g., energy savings), these studies are still essentially bottom-up engineering approaches. In economic potential studies, customers are typically expected to adopt a particular measure if the investment meets an economic hurdle rate (e.g., a certain

²⁵ Analysts describe the existence of an energy efficiency “gap”—that customers and firms do not undertake investments in energy efficient equipment that appears cost-effective on an estimated life-cycle basis and customers appear to require returns for investments in energy efficiency equipment that significantly exceed market interest rates for saving or borrowing (Sanstad et al. 2006). A number of market barriers and failures have been proffered to explain this gap (Brown 2001, Levine et al. 1995, Golove and Eto 1996, Jaffe and Stavins 1994, Sanstad and Howarth 1994). Market potential represents the amount of energy efficiency that can be achieved if policies and programs are put in place to overcome these barriers, recognizing that no interventions will be able to overcome all impediments to full realization of economic potential.

benefit/cost threshold) that is assumed to match customers' implicit required investment payback times.²⁶ Market potential studies account for additional factors that may limit uptake—even in the face of policies and programs to support energy efficiency—such as lack of access to information, limited availability of energy-efficient equipment in the marketplace, and “split incentive” barriers in which the person investing in the equipment is not in a position to receive the savings (e.g., landlord and tenant relationship).

The notion of energy efficiency as an attractive, low-cost resource is increasingly accepted by state and federal policymakers and a track record has been established in many states.²⁷ Several recent energy efficiency market potential studies focus on estimating maximum achievable market potential, often drawing upon the “best practices” experience of energy efficiency program administrators to estimate annual market penetration and saturation rates.²⁸

The context and motivations for estimating demand-response market potential are somewhat different. To a large extent, federal and state policymakers are convinced that demand response is a critical feature of a well-functioning and efficient wholesale and retail electricity market.²⁹ However, there is no consensus on how much demand response is necessary or desirable, in part because of limitations in analytic methods.

2.2 Approaches Used to Study Demand Response Market Potential

Studies of demand response market potential necessarily involve estimating two separate elements: *participation*, or the number of customers enrolling in programs or taking service on a dynamic pricing tariff; and *response*, quantities of load reductions at times of high prices or when curtailment incentives are offered. Among the seven demand response market potential studies and tools reviewed for this study, four distinct approaches were used (see Appendix A for a summary of the studies). We introduce these approaches below, commenting briefly on their main advantages and disadvantages.

Customer surveys

One approach is to survey utility customers about their expected actions if offered hypothetical demand response options. Resulting participation rates and expected load curtailments are used to estimate market potential. This approach has the advantage of using information obtained locally, but its major drawback is that the responses are highly subjective—customers may not know what they would actually do (particularly if

²⁶ Despite years of experience estimating the economic potential for energy efficiency, there is still considerable debate regarding customers' actual economic decision-making thresholds. For example, Sanstad et al. (2006) estimated implicit discount rates from energy efficiency investments presented in several studies conducted between 1978 and 1984, and found a range from 25% to 300% across a range of measures.

²⁷ For example, the National Action Plan for Energy Efficiency (2006) represents a broad consensus of policymakers, regulators, utilities and stakeholders on energy efficiency benefits and best practices.

²⁸ See, for example, WGA CDEAC (2006).

²⁹ For example, Section 1252 of the U.S. Energy Policy Act (EPACT 2005) recognizes demand response as a high priority federally, and provides guidance to states to do so as well.

they have no prior demand response experience), or may respond strategically. We found only one example of this approach.

Benchmarking

Benchmarking approaches apply participation rates and load reductions observed among customers in other jurisdictions to the population of interest. The advantage of this approach, relative to customer surveys, is that it relies on actual customer experience and actions. However, it assumes that any differences in the customers and market context have an insignificant impact on participation and load response. In reality, variables such as the mix of customers (e.g., size, end uses, business activity), market structure (e.g., vertically integrated utility, organized wholesale markets), the specific tariff or program design, and the level and volatility of prices or incentives may impact actual response. Only one of the reviewed studies adopted this approach.

Engineering approach

Four of the seven studies used bottom-up engineering techniques, similar to those used to estimate energy efficiency market potential. They are all variations on the approach of applying assumed participation and response rates to data on local customers, loads or equipment stock. The participation and response rates may come from actual data observed in other jurisdictions, a “Delphi” approach, in which experts are surveyed, or customer surveys.³⁰ These rates are typically assumed to be constant, regardless of price or incentive levels. This approach may be appropriate for *dispatched* demand response programs (e.g., direct load control) in which a utility or program operator remotely controls a customer’s energy-using equipment. However, demand response options for large customers—in which customers initiate load reductions in response to a price signal or a specified incentive payment (and sometimes a penalty provision)—are significantly different. Behavior, not physical circumstances, dictates the outcomes, making the engineering approach less tractable for this type of demand response option.

Elasticity approach

This approach, adopted by one of the reviewed studies, involves estimating price elasticities, preferably using an econometric demand model, from the usage data of customers exposed to demand response options. After determining an expected participation level (using a benchmarking or other approach), price elasticities are applied to the population of interest to estimate load impacts under an expected range of prices or level of financial incentives to curtail load. Like the benchmarking approach, elasticities are based on actual customer response. They also quantify the relationship between customer behavior (load reductions) and price (the primary motivation for undertaking changes in consumption). When demand models are used to estimate elasticities, variables can be introduced to account for customer- or market-specific factors that influence price response, enabling the translation of results to other jurisdictions that may vary in these factors.

³⁰ See Appendix A for descriptions of the individual approaches.

2.3 What Makes Demand Response Different from Energy Efficiency?

While energy efficiency and demand response both involve modifying large customers' use of and demand for electricity, they differ in the following important ways:

The nature of participation

The installation of high-efficiency equipment or appliances typically involves a one-time investment decision by the customer, and program operators recruit new customers (or new projects with repeat customers) in each year. For demand response, participation involves two steps: enrolling in a program or tariff, usually on an annual (or other periodic) basis; and providing load reductions during specific events (e.g., system emergencies or periods of high prices). Demand response participation is ongoing and typically changes on a yearly (or seasonal) basis as some customers drop out of programs (or tariffs) and new participants sign up. At the same time, participation by all customers is probably not necessary to achieve the goals of reducing market price spikes, mitigating market power, or averting blackouts. This is in contrast to energy efficiency, where more is usually better (up to an avoided-cost or cost-effectiveness threshold). Finally, customer participation in certain energy-efficiency programs is often tied to equipment replacement cycles or new construction, which affects penetration rates. For demand response, this is typically not the case.

The drivers of benefits

Once customers have made the decision to participate in a program (or tariff), the benefits of that participation—energy or demand savings—derive from very different sources. For energy efficiency measures, the level and persistence of savings are largely a function of the technical characteristics of the high-efficiency equipment or appliance relative to current practice or existing equipment (with some complicating customer-usage factors).³¹ Amenity and service levels are assumed to remain constant. In contrast, demand response load reductions are largely a function of customer behavior—their willingness and ability to curtail loads for short periods of time in response to high prices or system emergency events, while minimizing any negative impacts on amenity and service levels. More widespread adoption of automated demand-response technologies and strategies could make demand response load curtailments more predictable and sustainable, diminishing some of these differences.

The time horizon and valuation of benefits

With some exceptions, energy efficiency measures result in a reasonably certain benefit stream of energy (kWh) savings with multi-year duration.³² Energy-efficiency potential

³¹ Customer behavior may affect the energy efficiency technical savings potential in a variety of ways. For example, customers may change their usage of the equipment or building, remove or replace the equipment before the end of its economic lifetime, or provide improper or insufficient equipment maintenance. For certain types of energy efficiency measures, decay rates in equipment performance are assumed over the measure lifetime.

³² A wide body of literature is available on the persistence of savings from energy efficiency measures, making it possible to model expected savings decay rates due to a range of technical and social factors.

studies typically value benefits to participants using expected retail electricity rates with escalation factors over a specified time horizon.³³ In contrast, from a customer perspective, benefits from demand response programs may be highly variable and are often short-term.³⁴ They are driven by short-term load curtailments or demand (kW) savings and these benefits last only as long as the customer remains a participant in the program (or is exposed to and responds to dynamic prices). Modeling demand response benefits to customers requires examining short-term price fluctuations (e.g., peak/off-peak price differentials on a given day) or estimating the value of lost load (for demand response programs that lower the probability of outages).

Level of uncertainty regarding benefits (and costs)

The level of uncertainty that large customers face in evaluating the costs and, particularly, the benefits of demand response participation is much higher than for energy efficiency. For example, in some years, emergency demand response programs are called infrequently if at all, while in other years there may be upwards of 20-30 hours of curtailments events. Customers enrolled in dynamic pricing tariffs may not face high prices for several years, but then experience volatile and/or sustained price increases for several months in a row during other years. This probably translates to higher investment hurdle rates—customers may expect much higher benefit/cost thresholds as compensation for the inherent risk. Over time, this should become less of an issue, as more customers develop demand-response experience.

Important interactions

Another, less critical, but nonetheless important, difference is the type of interactive effects that must be accounted for in the modeling process. For energy efficiency, interactions between measures can affect outcomes. For example, the installation of high efficiency lighting may reduce the space-conditioning savings potential in the same building, because waste heat from the lights is removed.³⁵ For demand response, interactions may arise between different demand response options, depending on program rules (e.g., customers may be allowed to simultaneously elect a dynamic pricing tariff and participate in an emergency demand response program). Another possible source of interaction is the frequency, duration and timing of high prices or curtailment calls. For example, “response fatigue”, or a reduction in willingness or ability to curtail, may occur if customers are asked to curtail for several consecutive days.

³³ Energy efficiency savings are often characterized as the difference between a baseline energy usage level and a high-efficiency scenario. This potential may then be modified by incorporating customer acceptance rates (e.g., based on an assumed benefit threshold) or other factors.

³⁴ However, customers on hourly pricing tariffs can also benefit from lower prices, relative to a revenue-neutral fixed price tariff, in the majority of hours. Moreover, to the extent that fixed-price tariffs include a risk premium relative to hourly pricing, this can represent another source of savings to customers.

³⁵ It is common to include a 5–10% correction for this effect in energy-efficiency potential studies.

2.4 A Different Approach to Demand Response Market Potential for Large Customers

Given differences in the motivations for undertaking energy efficiency and demand response potential studies, and in the features of these two demand-side resources, it is clear that merely translating or adapting methods from one to the other may not be appropriate for all options. We summarize this conceptual discussion with the following observations and recommendations on methods for estimating demand response market potential:

- **For residential and small commercial direct load control programs, customer load impact estimates can be derived from bottom-up engineering approaches or statistical evaluations of samples of participating customers with appropriate metering.** These approaches are also commonly used to estimate energy efficiency savings potential.
- **For large customer demand response options, that rely on customer-initiated response to prices (e.g., hourly or critical-peak pricing) or curtailment incentives (e.g., short notice emergency program, price response event program), we recommend an elasticity approach for estimating load reductions in market potential studies.**³⁶ The elasticity approach explicitly links response to prices and customer behavior. When demand models based upon economic theory are used to estimate elasticities, they also enable the translation of experience from other jurisdictions with adjustments for differences in customer- and market-specific factors.
- **Participation should be thought of in terms of market *penetration* in a given year (or other relevant time period).** Unfortunately, participation is the most difficult aspect of demand response options to estimate, due to a limited experience base. With time and experience, however, this should improve.
- **With the current limited experience base on which to draw, approaches that rely on customer survey response to hypothetical demand response options, or benchmarking, are probably not all that meaningful.** The “best practices” approach, which has been used in some energy efficiency market potential studies, makes most sense when there is a larger experience base (i.e., mature programs offered by many utilities or ISOs over a lengthy period).

The remainder of this report focuses on a framework, centered on the use of price elasticities, for estimating the market potential of demand response options, such as dynamic pricing tariffs (e.g., real-time pricing, critical-peak pricing), emergency

³⁶ We note, however, that demand response programs involving reserve or capacity payments and/or penalties for non-response (e.g., interruptible rates, capacity programs) present difficulties in estimating elasticities, because customer incentives are less clearly tied to individual events.

programs, and economic/demand bidding programs, that are typically offered to large commercial and industrial customers.

3. A Framework for Estimating Large Customer Demand Response Market Potential

In this section, we propose a conceptual framework for estimating demand response market potential among large C&I customers in a given jurisdiction or utility service territory. This framework involves the following five steps (see Figure 3-1):³⁷

- *Establishing the study scope*—identifying the target population and types of demand response options to be considered;
- *Customer segmentation*—identifying “customer market segments” (groups of customers with similar characteristics that are expected to respond in similar ways) among the target population;
- *Estimating net program penetration rates*—using available data to estimate customer enrollment in voluntary programs and customer exposure to default pricing programs;
- *Estimating price response*—selecting an appropriate measure of price response given available data and developing elasticity estimates applicable to the identified customer market segments; and
- *Estimating load impacts*—combining the above steps to estimate the level of demand response that can be expected from the target population at a reference price.

Each of these steps is discussed in the sections that follow and illustrated with examples in section 4.

3.1 Establishing the Study Scope

The first step in our framework is to define the study scope at a high level. Specifically, this involves deciding on the target customer population and the types of demand response options to be considered in the market potential study or market assessment.

The target population is typically defined by the type of customer (e.g., commercial, industrial, agricultural), and/or customer size thresholds (e.g., threshold peak demand level). Policy and regulatory considerations often influence the choice of target population.

Different types of demand response options may induce different levels of demand response impacts among customers.³⁸ For example, everyday hourly pricing tariffs that are linked to wholesale electricity market prices may elicit smaller load reductions on a given day than an emergency program that, depending on program design, may provide a larger curtailment incentive to customers (Goldman et al. 2005, Neenan et al. 2003).

³⁷ For demand response options, such as direct load control programs, in which a utility or program operator directly cycles down a participating customer’s equipment, engineering approaches may be more appropriate (see section 2).

³⁸ For a description and classification of various demand response options, see chapter 2 of DOE (2006).

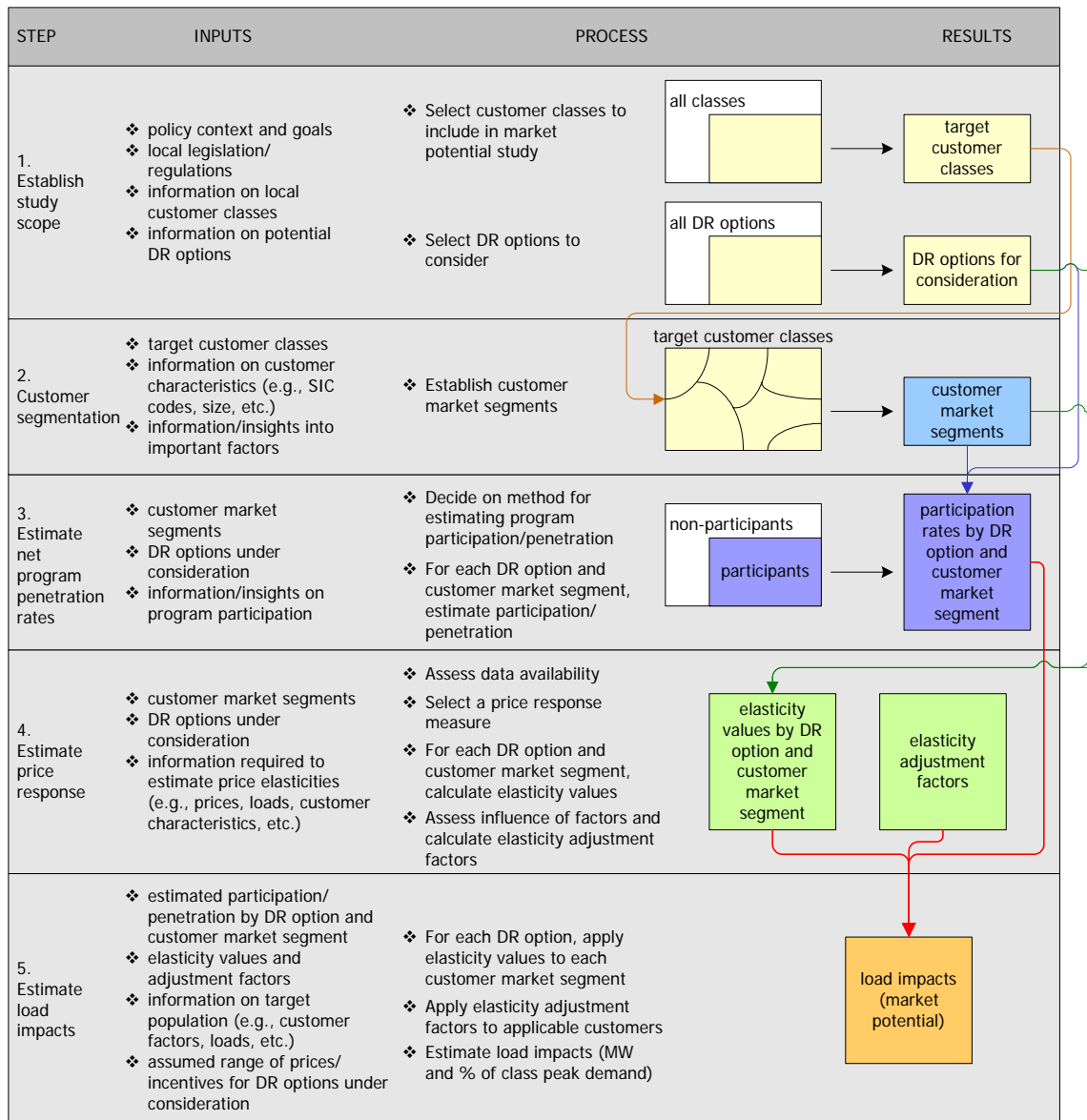


Figure 3-1. Steps for Estimating Demand Response Market Potential

Moreover, certain types of programs or tariffs are more appropriate for certain market structures than others—for example, default-service real-time pricing (RTP) is more likely to be accepted by customers if implemented in the context of retail choice. Market-based, bidding-type programs may also be facilitated by the presence of organized wholesale energy (and/or capacity) markets. Therefore, policymakers will wish to determine up-front which types of demand response options are feasible and appropriate for the target customer population and the incumbent market structure.

The selection of customer groups and specific program offerings can later be refined as more responsive participants are identified in the process of conducting the market potential study.

3.2 Customer Segmentation

With input from policymakers and sponsoring entities (e.g. utilities, ISOs, RTOs), analysts conducting the demand response market potential study should use available information about the target population to identify customer market segments that are expected to respond in similar ways, or that could be approached with specific marketing strategies or program designs. These groups will be analyzed separately in subsequent steps of the market potential analysis so, ideally, they should be refined enough to capture significant trends in customer willingness to participate in and respond to demand response programs or dynamic pricing tariffs.

For large customers, business activity is often strongly correlated with both willingness to participate in demand response programs (or remain on default-service hourly pricing), and willingness and ability to respond to high-price or reliability events by temporarily lowering demand (Goldman et al. 2005, Neenan et al. 2003). Typically, information on large customers' lines of business is available to utilities and policymakers in the form of standard industrial classification (SIC) codes. SIC codes provide quite detailed information about the type of industry a specific customer is engaged in. Analysts usually aggregate these codes into a handful of groupings that provide a reasonable sample size in each, yet distinguish groups of customers with substantially different activities or operating cultures, and similar energy usage characteristics (e.g., load factor and timing of usage). For example, in Goldman et al. (2005), large customers (with peak demand above 2 MW) were divided into five categories: manufacturing, government/education, commercial/retail, healthcare and public works.

3.3 Estimating Net Program Penetration Rates

Next, it is necessary to estimate customer participation rates for the demand response options included in the study.³⁹ In the context of demand response, participation can imply: (1) customer enrollment in voluntary programs and tariffs, or (2) the retention of customers in programs or tariffs implemented as the default service (i.e., the number of customers who do not switch to an alternative offering).

Demand response participation is often fluid. Customers may enroll in a program for one or more years, and subsequently drop out. They may even subsequently re-enroll in the program, or others may take their place. With some exceptions, the benefits of customer participation are only realized while the customer is enrolled in the program (or exposed to hourly prices).⁴⁰

³⁹ Practically speaking, no demand response offering will ever experience full participation by all customers to whom it is offered or imposed. In theory it might be possible to impose a mandatory dynamic pricing tariff. However, if alternatives are not offered by the default utility supplier or a competitive retail market is not sufficiently competitive, policymakers are likely to experience strong customer resistance to such a policy.

⁴⁰ However, the experience of responding to a particular program may provide benefits beyond that particular program if the customer subsequently exhibits demand response behavior in other programs or dynamic pricing options that were learned in the initial program.

Thus, participation in demand response options can be viewed as *penetration* in a given year “n” (or other applicable timeframe), as follows:

$$\text{Penetration}_n = \text{participants}_{n-1} - \text{dropouts}_n + \text{new enrollees}_n$$

This can be estimated separately for each customer market segment defined in the previous step, and the results added up to determine the overall penetration for the population of eligible customers.

This way of thinking about demand response potential is useful for evaluating an established program over multiple years, particularly in the context of changes to program rules or incentives, or to the level and/or volatility of market prices. From the standpoint of a new, hypothetical program, it may be acceptable to view participation as penetration in a “typical” year of a mature program, with the understanding that a multi-year ramp-up period will be necessary, and that ongoing penetration may be subject to fluctuations due to factors both within and out of the program operator’s control.

An important aspect of demand response participation is the interaction of multiple programs and dynamic pricing tariffs. In some situations, program rules may limit customer participation in more than one demand response option. Where such rules are known in advance, the mutual exclusivity of programs should be taken into account when establishing penetration estimates for individual programs. In other cases, customers who are enrolled in multiple demand response options may behave differently than customers participating in a single option. For example, in some jurisdictions, it is allowable for customers that face day-ahead hourly prices for their electricity commodity tariff to participate in emergency or demand bidding programs offered by an ISO or RTO. The potential load response for such customers is probably not as high as the sum of the estimated response for a customer in an hourly pricing program and for a customer in an ISO/RTO program. Such interaction effects, if deemed sizeable, should be accounted for in estimating overall load impacts (see section 3.5).

Analysts have used a number of methods to estimate penetration rates of demand response programs (see Table 3-1). Each of these methods has pros and cons, in part because there is not yet a broad set of information on customer response to various demand response options in a variety of settings. Program penetration rates present the largest uncertainty in this framework, because experience is piecemeal, and because of data limitations. Whatever the chosen method (or methods), we strongly recommend evaluating the impact of a range of participation levels, rather than relying on a single point estimate. In Table 3-1, we describe the approaches used by various analysts to estimate program penetration.

The “Delphi”, or “expert judgment”, method is a heuristic, or intuitive, method of establishing penetration of demand response programs. SCE (2003) employed this approach, asking several demand response experts to provide estimates of participation in a variety of demand response programs. Another example is Violette et al.’s (2006) analysis of the value of demand response for the International Energy Agency’s Demand

Table 3-1. Methods of Estimating Demand Response Penetration Rates

Method	Description	Advantages	Issues/Questions
Delphi (expert judgment)	Solicit estimates from a panel of individuals with experience or insight	Relatively simple method which may provide reasonably accurate estimates	<ul style="list-style-type: none"> Results are subjective—what constitutes an expert? Requires a method of resolving divergent estimates
Translated experience	Use actual participation rates for demand response programs implemented for similar market segments or target populations, and/or in markets with similar supply conditions and market structure	<ul style="list-style-type: none"> Uses actual data on realized penetration rates of implemented demand response options Depending on the data source(s), can provide detailed estimates 	<p>Assumes that the customers, market segments, market supply conditions and other characteristics of the population on which estimates are based are identical and directly translatable to the population to which the estimates are applied.</p> <p>Potential sources of bias include:</p> <ul style="list-style-type: none"> the method of setting prices/incentives the level and volatility of prices/incentives the market structure (e.g., organized market with ISO/RTO vs. vertically integrated utility in region without ISO) differences in the customer base (e.g., different types of manufacturing facilities in different regions) differences in customer experience with load management and demand response climatic differences
Benefit threshold	Set a minimum level of economic benefits required for a customer to participate (e.g. payback time)	Logical theoretical basis for modeling customer participation	<ul style="list-style-type: none"> Requires a subjective determination of how high the benefit threshold should be set for different customer market segments and/or individual customers as well as estimates of demand response costs Assumes that customers act rationally—in reality, not all customers will choose to participate, even if it benefits them
Choice model	Develop a statistical model of the factors that drive customer participation, using data from demand response programs implemented for similar market segments or target populations, and/or in markets with similar supply conditions	<ul style="list-style-type: none"> Provides a robust statistical method for estimating participation at a fine level of detail Uses actual data on customer participation from implemented demand response programs 	<p>Assumes that the customers, market segments, market supply conditions and other characteristics of the population on which estimates are based are identical and directly translatable to the population to which the estimates are applied.</p> <p>Potential sources of bias include:</p> <ul style="list-style-type: none"> the method of setting prices/incentives the level and volatility of prices/incentives the market structure (e.g., organized market with ISO/RTO vs. vertically integrated utility in region without ISO) differences in the customer base (e.g., different types of manufacturing facilities in different regions) differences in customer experience with load management and demand response climatic differences
	Develop a statistical model of the factors that drive customer participation, using survey data on expected choices by the population of interest	<ul style="list-style-type: none"> Provides a robust statistical method for estimating participation at a fine level of detail Uses data obtained from a sample of customers in the target population 	<ul style="list-style-type: none"> Customers survey responses based on hypothetical options may differ from their actual behavior when faced with real choices Surveys can be resource-intensive

Response Resources project, in which hypothesized, graduated increases in participation were assumed over a 15-year period, up to a level of 15 percent. The simplicity of the “Delphi” method is appealing, and in the absence of appropriate information sources or resources for a more systematic market penetration study it may be the most feasible approach. However, both the selection of the “experts” and the resulting estimates are highly subjective, and the resultant lack of transparency may be a problem in jurisdictions

where demand response implementation may be controversial. Moreover, if the experts' estimates diverge substantially, some (again subjective) method is necessary to resolve them.

Another option is to apply customer participation rates observed in another jurisdiction to the target population (see, for example, Gunn 2005). This has the advantage of using real customer adoption data, and is simple to implement. If customer market segments are well defined and are similar in the two customer populations, this can be an appropriate method. However, it is only as good as the assumption that the source population, market characteristics and demand response options are adequately similar to the population of interest to produce meaningful estimates.

An alternative method is to assume that participation is largely, if not wholly, driven by customers' expectations of benefits. This method can be used to estimate customer participation in a single program, or an array of programs. In the single-program case, customers are assumed to participate if their expected benefit exceeds a threshold level (e.g., a level of nominal dollar savings, or an average per unit electricity cost reduction) over a specified time period. If facing several, mutually exclusive program opportunities, customers are assumed to select the one with the greatest expected benefit (provided it meets a minimum threshold). This approach is appealing in that it does not rely on data from other programs and provides a simple, yet systematic method for estimating participation. However, determining the threshold benefit level entails major assumptions.⁴¹ Customer surveys can provide insights,⁴² but if customers do not understand or have much experience with the demand response program or tariff and its associated costs and benefits (e.g., through lack of direct experience), the results may have little resemblance to actual participation when the program is launched. Moreover, surveys can be expensive and time consuming.

Finally, choice models define customer adoption in terms of an "odds ratio"—the probability that a given customer (or average customer in a given customer market segment) will participate, given the choice. They are statistically robust models that can incorporate a variety of drivers for customer choice into a single model, providing greater predictive power than simply assuming participation rates directly. The economic theory behind a choice model is that customers' choices are driven by their (explicit or implicit) calculation of the marginal benefit of each choice.⁴³ They may be estimated using data on customers' actual choices in the face of real options, or surveys can be designed to collect data on customers' expected choices given proposed hypothetical options. Choice models

⁴¹ From a purely theoretical standpoint, a customer should be expected to participate in a program if the net benefit is greater than zero. However, uncertainty in a variety of factors that influence the actual level of benefits (e.g., customers' ability to respond on specific days, the level of prices/incentives, etc.), as well as customer and market barriers to participation (e.g., lack of customer awareness of program benefits, institutional barriers within customers' organizations, lack of priority of electricity usage, etc.), necessitate a higher participation benefit threshold. All of these factors should be taken into account when determining the benefit threshold.

⁴² See, for example, market research conducted by Momentum (2005) as part of the evaluation of California's Statewide Pricing Pilot.

⁴³ See Train (1993) for a complete description of the economic foundation for modeling customer choices.

have been estimated to describe large customers' propensity to switch from default-service hourly pricing to the competitive market and their likelihood of participating in ISO-sponsored demand response programs (Goldman et al. 2004, Neenan et al. 2003). These examples demonstrate the use of choice models in a similar context, but do not provide data that can be directly used to estimate demand response program participation. This could be done by evaluating the actual choices of customers in other jurisdictions who have been exposed to demand response options similar to those under consideration. However, the applicability of such models may be limited if the populations and market circumstances differ. Alternatively, a sample of customers in the population of interest could be surveyed about their expected choices, although this approach may be beyond the resources of most analysts charged with estimating market potential.

In summary, while a number of potential methods for estimating the penetration rates of demand response options show promise, limited data and experience confound reliable and statistically sound estimates at present, at least within a reasonable budget for a typical state or utility undertaking a market potential study. There is clearly a need for research to collect detailed data on the drivers for customers' participation in demand response options, and to develop robust models that can be more easily tailored to specific circumstances.

In section 4.2, we develop market penetration rates for five types of demand response programs and tariffs, disaggregated by market segment and customer size. Where possible, the estimates draw upon actual market penetration rates from evaluations of these programs and tariffs (i.e. translated experience), and a Delphi approach was used to fill in gaps. Our objectives are two-fold: (1) to illustrate the sensitivity of market potential estimates to program penetration rates, and (2) to provide some reasonable market penetration rate values for certain types of demand response programs and tariffs that reflect the experience of relatively mature programs (i.e., with 3–4 years of operation).

3.4 Estimating Price Response

The next step in this framework is to define the expected demand response potential of the customers that participate. This is done by assigning a *price elasticity* to each customer market segment, for each type of demand response option, using available information about how similar customers have responded to high prices or program events afforded by similar demand response options. This involves three steps. First, a measure of price response must be chosen, balancing theoretical consistency and data availability constraints. Second, elasticity values are developed for each market segment that will be applied to the target population to develop load response estimates. Finally, factors that affect demand response within the established customer market segments are evaluated and adjustments to the elasticity values are developed to account for their impacts on customer demand response.

3.4.1 Selecting a Measure of Price Response

Studies of consumers' response to changes in electricity prices typically express this response with one of three measures of price elasticity: the *price elasticity of demand*, the

elasticity of substitution, and the *arc price elasticity of demand*. All are estimated from a sample of customers' observed electricity usage data in the face of changing prices.

From a theoretical standpoint, the price elasticity of demand (also known as the “own-price” elasticity) provides the most consistent characterization of consumer behavior. However, its estimation requires data on customers' production output or the utility they derive from electricity usage that is usually not available, so few analysts have been able to estimate it directly.⁴⁴ A number of studies of large customer price response have instead estimated substitution elasticities, which are also grounded in economic theory and can be estimated without output data, but impose assumptions about how customers use electricity.⁴⁵ Arc elasticities are much easier to compute (only a limited number of observations of customer loads and prices are necessary) but this comes at the cost of limited explanatory power.

The tradeoffs between theoretical consistency and the amount of data required to estimate these three elasticity measures are summarized in Figure 3-2. As a general rule of thumb, analysts should choose the measure with the greatest theoretical consistency possible given available data.⁴⁶

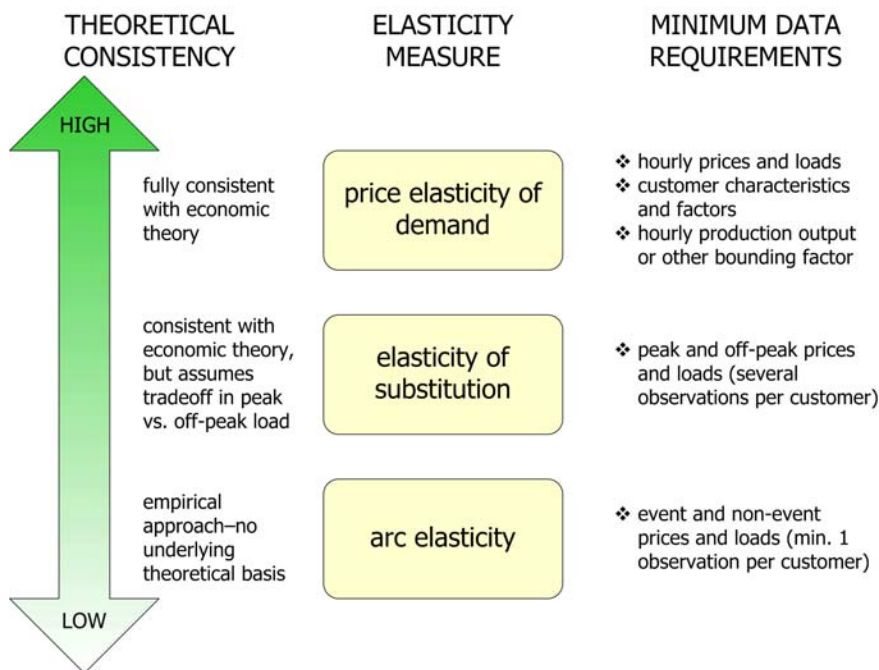


Figure 3-2. Features of Price Elasticity Measures

⁴⁴ When this method has been employed, a proxy for firm output or consumer's utility has been derived assuming they follow a cyclical pattern. The extent to which the individual firm or consumer differs from this pattern will determine the degree of inaccuracy in the resulting demand model.

⁴⁵ See, for example, Braithwait and O'Sheasy (2001), Boisvert et al. (2004), Caves et al. (1984), Goldman et al. (2005), King and Shatrawka (1994), and Schwarz et al. (2002).

⁴⁶ If multiple demand response options are being considered, different elasticity measures may be employed for each, as data requirements dictate. We have taken this approach in the examples provided in section 4.

Price Elasticity of Demand

The demand elasticity is a preferred measure of consumer response to changes in electricity prices from a theoretical standpoint. A behavioral model, grounded in economic theory, is overlaid on observed customer response data to develop a relationship between the quantity of electricity usage and prices. This relationship—the price elasticity of demand—is defined as the observed percentage change in a consumer’s electricity usage in response to a one percent change in the price of electricity. Mathematically, it is given by:

(1) $\sigma = \frac{dQ}{dP} * \frac{P}{Q}$, where P is the price of electricity and Q is the quantity of electricity used.

Although the concept is simple, properly estimating the price elasticity of demand requires that certain information be known about how customers use electricity. According to economic theory, the demand elasticity describes how customers decide to alter how much electricity to use, given their value for the amenity it provides, in response to a change in its price. Price elasticity must be evaluated in the context of other factors that may drive energy usage. For example, an industrial customer uses electricity as one of many inputs into a production process. The price of electricity is but one factor driving production—economic factors, availability of other inputs, the pace of customer orders, and other factors may change the customer’s demand for electricity by otherwise altering production. Thus, to properly characterize the extent to which electricity prices drive observed changes in usage, information on other factors that may drive electricity usage is needed. For large C&I customers, this could be production output (or an appropriate proxy).

Unfortunately, such information is, at best, burdensome to collect, and often not available at all. For large commercial and industrial customers in particular, production output (or service level) data tends to be regarded as highly confidential.

Elasticity of Substitution

The elasticity of substitution is also grounded in economic theory and can be used to estimate price response. It assumes that customers regard electricity as two distinct commodities—typically “peak” and “off-peak” electricity (defined by their timing during the day)—and that they make decisions about how much peak and off-peak electricity to use based on their relative prices.⁴⁷ The elasticity of substitution is somewhat less intuitive than the price elasticity of demand: it is defined as the ratio of the observed change in a customer’s peak and off-peak usage to a one percent change in the ratio of peak and off-peak prices.⁴⁸ The mathematical formula is:

⁴⁷ The overarching theory is that electricity is one of many inputs into a production process, and that the customer trades off the usage of one input for another (in this case, off-peak for peak electricity) in order to minimize costs.

⁴⁸ See Goldman et al. (2005) for a detailed discussion of the elasticity of substitution.

$$(2) \quad \sigma_{po} = \frac{d\left(\frac{Q_p}{Q_o}\right)}{d\left(\frac{P_o}{P_p}\right)} * \frac{\left(\frac{P_o}{P_p}\right)}{\left(\frac{Q_p}{Q_o}\right)}, \text{ where } P \text{ and } Q \text{ are price and quantity, and the subscripts } p$$

and _o refer to peak and off-peak periods.

To estimate a meaningful model, price and usage data in peak and off-peak periods, covering a range of prices, are needed for each customer included in the model. Ideally, customer characteristics and circumstances should also be incorporated into the model to evaluate the extent to which they explain the observed price response.

Arc Price Elasticity of Demand

The arc price elasticity is an empirical measure of price response that is not grounded in economic theory. It can be computed when insufficient data exist to estimate an economically consistent model—the tradeoff is a loss of specificity and explanatory power. Arc elasticities assume that customers change their electricity consumption strictly based on the ratio of a “background” price and an “event” price, without regard for output loss or other economic factors. The mathematical expression is:

$$(3) \quad \sigma_{ARC} = \frac{\left[\frac{(Q - Q_{CBL})}{Q_{CBL}} \right]}{\left[\frac{(P - P_B)}{P_B} \right]},$$

where P_B is the average retail price the customer would normally face (the background rate), Q_{CBL} is the customer’s expected normal level of usage at the background rate, P is the commodity price the customer either faces or is paid for curtailing in the event hour, and Q is the customer’s observed load during the event hour.

Measuring the Unobservable

It is impossible to directly measure the amount of energy that a customer would have used on a given event day if no event had occurred. How, then, is the quantity Q^{CBL} determined? This is the same dilemma faced by any demand response program that pays customers to curtail.

Program designers and analysts have come up with different methods of developing proxies for customer baseline loads (CBLs). In Appendix B, we describe the approaches of the programs included as data sources in section 4. For more information on the pros and cons of various methods, see Goldberg and Agnew (2003).

The advantage of this approach is that an estimate of price response can be obtained from only customer usage and prices (or incentives paid) during an “event” period, although the expected usage must be estimated somehow (see the adjacent textbox). Moreover, arc elasticities can be computed from a single event hour.⁴⁹

⁴⁹ At relatively low prices, arc elasticities have a tendency to pick up more “noise”—changes in usage due to extraneous factors that cannot be measured by the arc elasticity. Alternatively, when prices reach much higher levels, it is assumed that the change in consumption is truly driven by the change in price, thus improving the accuracy of the arc elasticity.

However, this formulation for price elasticity has limited application because it provides a highly localized, event-specific measure of behavior that does not systematically take into account any of the other factors that can influence how a customer responds. The load response at each event can vary considerably. For example, on a very hot day, a customer may be using much more space conditioning energy than usual, but be willing to sacrifice comfort for cash, and reduce this load substantially. The result could be an even greater relative reduction than on a cooler day; in other words, a higher arc elasticity. Another customer might be fulfilling an important commercial obligation that requires it to operate at full capacity, and not curtail at all, regardless of the price. An arc elasticity embodies factors other than price, but provides no way to measure their contribution to the response.⁵⁰ We therefore recommend that arc elasticities be used only when the data required to estimate other elasticity measures are not available.

3.4.2 Calculating Elasticity Values

Having chosen an elasticity measure, the next step is to estimate elasticity values for each customer market segment and demand response option included in the study. This requires information on customer response obtained from studies of similar implemented programs or tariffs. Ideally, estimates should draw on as many data sources as possible—where multiple programs or tariffs of a similar type are available, the data can be pooled. Although there are currently few sources of information for certain types of demand response option, over time it should be possible to develop elasticity estimates from a wider base of program experience and data.

3.4.3 Accounting for Factors that Influence Price Response

Studies of customer price response indicate that there is considerable diversity in how customers respond to similar prices and incentives, even among customer market segments (Goldman et al. 2005, Neenan et al. 2003, Schwarz et al. 2002). Table 3-2 summarizes factors that have been observed or theorized in various studies to differentiate when and how customers respond. External factors, such as high-price or program event characteristics and weather, are distinguished from customer-specific characteristics or circumstances, such as customer experience, ownership of onsite generation and other enabling technologies, and electricity intensity.

The impacts of external and customer-specific factors can be quantified and incorporated into market potential studies in three ways:

- they can be included directly in a customer demand model;
- an *ex ante* regression analysis can be used, with the factors as independent variables and estimated elasticities as the dependent variable; and
- simple statistical methods, such as chi-square tests or cross-tabulations, can be used.

⁵⁰ These factors are all associated with price, because that is the only variable in the arc elasticity equation used to explain changes in consumption.

Table 3-2. Factors that May Influence Demand Response

Factor	Description	Impact on Response
EXTERNAL FACTORS		
Event duration	<ul style="list-style-type: none"> Duration of individual events (e.g., in hours) 	<ul style="list-style-type: none"> Some customers may not respond unless high hourly prices or incentives are applicable for a block of several hours Some customers may be unwilling to curtail for long periods (e.g., more than four to six hours)
Event frequency	<ul style="list-style-type: none"> Overall frequency of events in a particular season 	<ul style="list-style-type: none"> If events occur too frequently, customers may be unwilling or unable to continue load curtailments (this is known as “response fatigue”) Conversely, experience gained from multiple events can enable customers to fine-tune their curtailment strategies
Event clustering	<ul style="list-style-type: none"> Distribution of events over time (e.g., clustered on consecutive days vs. isolated incidents) 	<ul style="list-style-type: none"> Clustered events may cause “response fatigue”—reduced willingness or ability of customers to respond
Weather	<ul style="list-style-type: none"> Temperature and humidity are strong drivers of HVAC usage Increased HVAC usage drives overall system demand and prices 	<ul style="list-style-type: none"> Weather-sensitive loads (e.g. air conditioning) may be somewhat discretionary; some customers may respond more when prices are high or system emergencies are perceived Conversely, some customers may be unwilling to reduce or curtail air conditioning loads during prolonged or extreme weather events
CUSTOMER-SPECIFIC FACTORS		
Training, awareness and past experience	<ul style="list-style-type: none"> Past participation in similar demand response programs or tariffs, or experience managing energy commodity risk (e.g. gas markets) Attendance at training workshops Technical audits or information 	<ul style="list-style-type: none"> May enhance customers’ acceptance of demand response options and ability to respond
Onsite generation	<ul style="list-style-type: none"> The presence of onsite generation equipment (e.g., backup generators, gas turbines, fuel cell or renewable generation technologies) at customers’ facilities 	<ul style="list-style-type: none"> Subject to environmental regulations, onsite generation allows customers to respond without interrupting electric end uses Provides customers with more response flexibility
Enabling technologies	<ul style="list-style-type: none"> Energy management controls systems (EMCS)—provide customers with the means to program equipment (e.g., HVAC or lighting control systems) usage changes in response to demand response events Energy Information Systems (EIS)—allow customers to analyze their load usage patterns, establish their baseline energy usage, access information about demand response events or prices, and identify strategies for load curtailment 	<ul style="list-style-type: none"> EMCS and EIS can help improve the persistence and sustainability of load curtailments, and provide immediate feedback to customers on load curtailment performance
Electricity intensity	<ul style="list-style-type: none"> Electricity costs as a share of customers’ operating expenses 	<ul style="list-style-type: none"> Customers whose operations are highly electricity-intensive may be more likely to participate in and respond to demand response options in order to minimize costs Conversely, high-intensity users may view their electrical end uses as non-discretionary, making them less likely to participate or respond
Business or operational processes	<ul style="list-style-type: none"> Features of customers business processes that impact the flexibility of their response (e.g., industrial process equipment, three-shift operations, facilities at multiple geographic locations) 	<ul style="list-style-type: none"> Certain types of industrial customers that can shift usage by rescheduling industrial processes (e.g., batch processes) or equipment usage (e.g., arc furnaces, aluminum smelters) may be more price responsive

From a statistical standpoint, the first approach is often preferable. However, depending on the demand model used, including variables directly in the model can add substantial

complexity, to the point where it becomes impossible to produce a stable representation of demand.⁵¹ The *ex ante* regression approach can provide a feasible alternative. However, to estimate a statistically robust regression, a large number of observations is necessary, and collecting information on customer-specific factors (e.g., through customer surveys) can be challenging. Simple statistical tests are the easiest approach to implement, but cannot account for interactions between multiple correlating factors. They can, nonetheless, provide qualitative insights to enable categorization of responsive and non-responsive customers in each category.

Factors found to influence price response can be used to adjust the elasticity estimates. For example, if customer ownership of a specific enabling technology is found to increase demand response, then separate elasticity estimates can be applied to customers with and without that technology in the target population to achieve a more refined overall market potential estimate. This is demonstrated with an example for onsite generation in section 4.3.2.

While factor-adjusted elasticity estimates can provide more accurate estimates of market potential, their use is only practical if information on the presence of the factors is accessible. Not only must factor-specific information be available among the customers from whose response data elasticity estimates are derived, but also among the target population whose demand response market potential is to be estimated.

3.5 Estimating Load Impacts

The final step in this framework is to pull together all the pieces to estimate load impacts. The estimation of load impacts should be done separately for each demand response option under consideration in the study. As noted in section 3.3, analysts may wish to account for interactive effects arising from program eligibility rules (or customer's operational constraints) that limit participation in multiple programs.

For each customer market segment, program penetration rates estimated in step 3 should be applied to the target population in that segment. Then, elasticity values are applied to the customers in each market segment. These elasticities are then adjusted for individual customers for whom the elasticity adjustment factors developed in the last step are applicable.

Once each customer has been assigned an elasticity value, it remains to translate the results into an estimate of load impacts for a range of expected prices or incentive levels. If the price elasticity of demand was used to characterize customer response, load impacts can be calculated directly for a given price. For substitution and arc elasticities, this task is somewhat more complicated and the methods for doing so are not well established. Here, we describe a method for each type of elasticity.

⁵¹ This is particularly difficult for non-linear models, such as the Generalized Leontieff model (see Goldman et al. 2005).

3.5.1 Estimating Load Impacts from Arc Elasticities

Given a set of prices, it is fairly simple to derive the percentage change in load from arc elasticity values using the following formula:

$$(4) \quad \% \Delta L = \sigma_{ARC} \times \left[\frac{(P - P_B)}{P_B} \right],$$

where σ_{ARC} is the elasticity value, P is the program's incentive payment rate (or dynamic pricing tariff's applicable rate during the high-price event), and P_B is the retail price the customer would normally face (the background rate).⁵² If an analyst knows something about the expected level of load (i.e. the CBL) during an event, then the percentage change in load can be translated into an estimate of the level of demand response according to the following formula:

$$(5) \quad DR = (-1) \times Q_{CBL} \times \% \Delta L$$

3.5.2 Estimating Load Impacts from Substitution Elasticities

Because the elasticity of substitution assumes that customers substitute peak for off-peak electricity, it is necessary to establish the proportion of electricity costs that are allocated to both these periods. Customers are also assumed to respond vis-à-vis the average price in each period, both in terms of the nominal changes in the peak and off-peak prices from their average levels, as well as the relative prices in the two periods. As a result, the following separate formulae are used to estimate peak load reductions and off-peak load expansion:⁵³

$$(6) \quad \% \Delta L_p = (\sigma_{po} \times C_o) \times \left[\left(\frac{P_o - \overline{P_o}}{\overline{P_o}} \right) - \left(\frac{P_p - \overline{P_p}}{\overline{P_p}} \right) \right]$$

$$(7) \quad \% \Delta L_o = (\sigma_{po} \times C_p) \times \left[\left(\frac{P_p - \overline{P_p}}{\overline{P_p}} \right) - \left(\frac{P_o - \overline{P_o}}{\overline{P_o}} \right) \right],$$

where C_o is the off-peak-period cost share as a percentage of the total daily electricity cost (e.g. 50%, 75%, etc.), C_p is the peak-period cost share as a percentage of the total daily electricity cost, P_o is the actual off-peak period price, P_p is the actual peak period price, $\overline{P_o}$ and $\overline{P_p}$ are the average off-peak and peak period prices. Applying equation (5) to equation (6) produces an estimate of the level of demand response (i.e., load reductions during peak periods). Similarly, applying equation (5) to equation (7) provides an estimate of the load impacts in off-peak periods (i.e., increase in load due to load shifting).

Once the load impacts have been established (in MW), they can be expressed as a percentage of the peak demand of the applicable customer class.

⁵² If the customer's otherwise applicable tariff is a time-of-use rate, then P_B should be the period price coincident with the timing of the event.

⁵³ These formulae assume the use of an Allen-partial elasticity of substitution.

4. Applying the Framework: Large Customer Demand Response Market Potential

We applied the methodology developed in section 3, using available data on large customer participation and response, to estimate the market potential of several types of demand response option at an illustrative urban utility. The purpose of this exercise is threefold:

- to demonstrate the implementation and use of the proposed methodology;
- to gather currently available data on large customer participation and response, which could be used by policymakers and other analysts in market potential studies; and
- to demonstrate, through the use of scenarios, the impacts of various factors on demand response market potential.

The first step in any market potential study is to define its scope (see section 3.1). In this example, we limit our analysis to large, non-residential customers, with peak demand ranging from 350 to 5000 kW or more. This is because we had access to individual customer level data from several large-customer demand response options, which facilitated estimation of participation rates and customer response by market segment and customer size.⁵⁴

We analyze five different types of demand response option in this example (see Table 4-1). These are by no means the only options possible; they simply represent those for which we had data to conduct this exercise.

It is important to recognize that we analyzed these options *independently*. That is, we did not account for possible interactions between different options, should they be offered simultaneously to a given set of customers.⁵⁵ Thus, our results likely *overestimate* the combined market potential for these demand response programs and dynamic pricing tariffs should two or more of them be offered to the same customers at once. Program designers that intend to offer a variety of demand response options should ensure that such interactions are accounted for in market potential studies.

The second step in the proposed methodology is to define customer market segments (see section 3.2). Following a recent study of large customer demand response (Goldman et al. 2005), we adopted the following five market segments that are well correlated with differences in large, non-residential customers' willingness to participate in and respond to demand response options:

⁵⁴ We did not have access to this level of data for smaller commercial or residential customers, although the same methods could be applied to smaller customers offered similar demand response options if the required data were available.

⁵⁵ If customers are offered more than one type of demand response option, they may face a tradeoff in choosing which programs to participate in, particularly if program rules prohibit multiple program participation. Even where customers are allowed and opt to participate in more than one option (e.g., default hourly pricing combined with a short-notice emergency program), their load response during program events may be enhanced by the dual incentives, yet will almost certainly be less than the sum of their response to each program in isolation.

- manufacturing (SIC 01–39),
- government/education (SIC 81–98),
- commercial/retail (SIC 50–79),
- healthcare (SIC 80), and
- public works (SIC 40–49).

Table 4-1. Demand Response Options Included in Market Potential Simulation

DR Option	Description
Optional hourly pricing	<ul style="list-style-type: none"> • A dynamic pricing tariff with bundled charges for delivery and commodity • Usually offered by vertically integrated utilities on an optional basis • Typical rate design is a two-part structure, in which a customer baseline load (CBL) is established and billed at an otherwise-applicable tariff rate, with deviations in actual usage billed at hourly prices
Default hourly pricing	<ul style="list-style-type: none"> • A dynamic pricing tariff in which distribution charges are unbundled from commodity charges • Usually offered by distribution utilities or default service providers in states with retail electric competition • Typical rate design includes demand and/or volumetric distribution charges, with all commodity usage billed at an hourly rate, often indexed to a day-ahead wholesale market
Short-notice emergency program	<ul style="list-style-type: none"> • A program that offers customers financial incentives for curtailing load when called by a program operator on short notice (i.e., 1-2 hours) in response to system emergencies • Typically, customer response is voluntary (i.e., in some programs, no penalties are levied for not curtailing when called)
Price-response event program	<ul style="list-style-type: none"> • A program that pays customers for measured load reductions when day-ahead wholesale market prices exceed a floor • Some programs may include bid requirements (i.e., customers are only paid for curtailments that they specify in advance) and/or penalties for failing to respond when committed
Critical-peak pricing	<ul style="list-style-type: none"> • A dynamic-pricing tariff similar to a time-of-use rate most of the time, with the exception that on declared “critical-peak” days, a pre-specified higher price comes into effect for a specific time period

The remaining three steps in our methodology are described with data and examples in the remainder of this section. First, we introduce the data sources used for each of the five demand response options evaluated. Then, we provide participation estimates for each program and tariff, drawing on the available data. Elasticity values, and adjustments for factors found to influence load response are then derived, again from available data. Finally, these data are combined to estimate demand response market potential using population data from an urban utility in the Northeastern U.S., demonstrating the impacts of various factors on market potential results with the use of scenarios.

4.1 Data Sources

We gathered data from six demand response programs and dynamic pricing tariffs offered by utilities and ISOs/RTOs in recent years (see Table 4-2). They span a range of geographical regions, market structures, and types of demand response option. The data sources all included electricity consumption data (although in some cases confined to declared event periods) and information on customer characteristics (in some cases limited to business classification and peak demand). The specific program and tariff designs are described in Appendix C.

Table 4-2. Data Sources

DR Option	Data Source(s)	Eligible Customers (peak demand)	Available Data Range	Reference
Optional hourly pricing	Central and Southwest (CSW) Utilities' (now American Electric Power) two-part RTP rate	> 1,500 kW	1998–2002 (summers)	Boisvert et al. (2004)
Default hourly pricing	Niagara Mohawk Power Corporation (NMPC), a National Grid Company, SC-3A tariff	> 2000 kW	2000–2004 (summers)	Goldman et al. (2005)
Short-notice emergency program	NYISO Emergency Demand Response Program (EDRP)	> 100 kW	2001, 2002, 2005	Neenan et al. (2003)
	ISO-NE Real-Time Demand Response (RTDR) Program	> 100 kW	2003, 2005	RLW Analytics and Neenan Associates (2003, 2004 and 2005)
Price-response event program	ISO-NE Real-Time Price Response (RTPR) Program	> 100 kW	2003–2005	RLW Analytics and Neenan Associates (2003, 2004 and 2005)
Critical-peak pricing	California Utilities ¹ Critical Peak Pricing Program	> 200 kW; > 100 kW for SDG&E	January 2003–September 2004	Quantum Consulting, Inc. and Summit Blue Consulting, LLC (2004 and 2006)

¹ Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) offer a critical-peak pricing tariff to large customers. The tariff design is quite different from that of the California Statewide Pricing Pilot that primarily targeted residential customers (Charles River Associates 2005), and the resulting customer response is correspondingly different.

4.2 Estimating Program Participation from Large Customer Program Experience

In section 3.3 we presented several approaches to estimating customer or load participation in demand response options. In this example, we use a combination of the “translated experience” and “expert judgment” approaches. Where possible, we used actual program participation data from the data sources in Table 4-2. We filled in missing

information by surveying program managers of similar types of demand response options, and inferring data from other market segments or programs.⁵⁶ Our goal was to estimate participation based on relatively mature programs⁵⁷ with 3–4 years of operation.⁵⁸

The resulting participation rates, presented in Table 4-3, were applied directly to the target population in our simulation exercise (see section 4.4). The estimates derived from “expert judgment” are distinguished in Table 4-3 from actual participation rates by italics and red font. In each case, participation is defined as the number of enrolled customers as a percentage of the number of eligible customers.⁵⁹ We report the information by customer market segment and peak demand level within a market segment.

The highest participation rates are observed for large customers (>1 MW) in the default hourly pricing tariff. We believe this is largely explained by the default nature of the tariff—participation is defined as *not* selecting an alternative electricity supplier, rather than as the conscious decision to sign up that characterizes the other programs and tariffs.⁶⁰

Another factor that strongly impacts participation rates is the definition and size of the eligible customer population. For the default hourly pricing tariff, only a specific set of large customers, with peak demand above 2 MW were eligible. In contrast, the other programs were open to significantly wider classes of customers. The threshold for the critical-peak pricing program was 100 or 200 kW (depending on the utility). For the ISO programs, eligibility is defined not by customer size class, but by a minimum allowable load reduction (i.e., 100 kW). To develop participation rates, we constructed the pool of

⁵⁶ Complete participation data were available for the default hourly pricing tariff and the critical-peak pricing program. For the two short-notice emergency programs, information on the number of participating customers was available from NYISO and ISO-NE. However, neither agency collects information on the number of customers eligible for their programs. Consequently, we constructed eligible population data from information obtained from multiple sources—evaluation reports for the two programs, data from the Energy Information Administration (EIA 2005), the Commercial Building Energy Consumption Survey database (EIA 2003), and personal communication with ISO and utility staff. The largest information gap was presented by the optional hourly pricing tariff.

⁵⁷ As noted in section 3.3, participation rates can fluctuate over time, and it is useful to track participation on an annual basis (i.e., penetration in a given year). However, for an initial market potential study that seeks to estimate the amount of load response that can be expected from a particular program or tariff, it is appropriate to base estimates on participation observed for relatively mature programs.

⁵⁸ It is worth noting that Georgia Power’s optional hourly pricing tariff experiences extraordinarily high participation rates—in all business categories with peak demand above 1 MW, participation is 50% or more (Kubler 2006). As this program has been in operation for over a decade, and its tariff design provides reasonably certain benefits to participating customers, we believe this represents an upper bound on participation rates in optional RTP tariffs, and we do not adopt these rates for our simulation.

⁵⁹ Participation could, alternatively, be defined as the amount of enrolled customer load as a percentage of eligible loads.

⁶⁰ The default hourly pricing participation rates do not include those customers that switched to competitive retailers and entered into contracts in which they faced hourly prices indexed to day-ahead or real-time markets for some or all of their load. In Goldman et al. (2005), the authors provide aggregate estimates of the percentage of customers willing to face hourly prices overall, but data limitations (i.e. customer survey non-response) preclude estimates at the market segment level.

eligible customers, assuming that the 100 kW minimum load reduction would be feasible among customers with peak demands of 350 kW and above⁶¹—thus, a very large number of non-residential customers in New York and the New England states were considered “eligible” for the ISO programs. Consequently, even though the actual number of participants (100–400 customers) is comparable across the programs and tariffs, the denominators range from hundreds to thousands of eligible customers.

Table 4-3. Participation Rates in Demand Response Programs and Dynamic Pricing Tariffs

DR Option	Business Type	Customer Size (peak demand)			
		0.35–0.5 MW	0.5–1 MW	1–2 MW	>2 MW
Optional hourly pricing	Commercial/retail	<i>0%</i>	<i>0%</i>	<i>1%</i>	<i>2%</i>
	Government/education	<i>3%</i>	<i>4%</i>	<i>6%</i>	<i>25%</i>
	Healthcare	<i>0%</i>	<i>0%</i>	<i>1%</i>	<i>2%</i>
	Manufacturing	<i>3%</i>	<i>5%</i>	<i>6%</i>	<i>25%</i>
	Public works	<i>0%</i>	<i>0%</i>	<i>3%</i>	<i>20%</i>
Default hourly pricing	Commercial/retail	<i>4.3%</i>	<i>11%</i>	<i>50%</i>	43%
	Government/education	<i>4.2%</i>	<i>10%</i>	30%	42%
	Healthcare	<i>0.7%</i>	<i>1.8%</i>	50%	7.1%
	Manufacturing	<i>3.3%</i>	<i>8.3%</i>	29%	33%
	Public works	<i>3.7%</i>	<i>9.2%</i>	50%	37%
Short-notice emergency program	Commercial/retail	1.2%	23%	5.5%	20%
	Government/education	0.3%	5.3%	2.6%	9%
	Healthcare	0.6%	4.2%	4.3%	22%
	Manufacturing	0.2%	15%	17%	23%
	Public works	1.1%	10%	67%	17%
Price-response event program	Commercial/retail	0.3%	0.8%	1.8%	5.7%
	Government/education	0.3%	2.9%	4.1%	10%
	Healthcare	0.3%	1.6%	8.9%	22%
	Manufacturing	5.7%	10%	9.1%	30%
	Public works	0.1%	0.2%	0.4%	1.1%
Critical-peak pricing	Commercial/retail	0.9%	3.1%	5.2%	4.2%
	Government/education	1.5%	4.1%	2.3%	1.9%
	Healthcare	<i>0.9%</i>	<i>3.1%</i>	<i>5.2%</i>	<i>4.2%</i>
	Manufacturing	0.9%	4.5%	7.3%	6.9%
	Public works	1.2%	3.3%	1.3%	2.8%

Note: *Red-italicized* figures are based on expert judgment.

A number of other factors may also influence rates of customer participation in demand response programs and tariffs. Most obviously, program design features—such as the structure and level of incentive payments, penalties for non-performance, and the

⁶¹ Though allowed in the program rules, load aggregators were not that active in these short-notice emergency demand response programs (although they were active in the NYISO ICAP/SCR program). With aggregation, the pool of “eligible” customers would be even less well-defined.

duration, frequency and advance notice of events—may affect customer decisions to enroll. Other program-specific factors may include customer familiarity with and/or the reputation of the entity administering the program, the effectiveness of marketing and/or customer education efforts, and the availability of technical or financial assistance. Given the small size of our sample (six programs) it is difficult to draw conclusions about which program designs encourage or discourage participation. Nonetheless, evaluations of some of these programs did examine drivers for participation, with statistically robust results (see Appendix D for a summary of these findings).

4.3 Developing Elasticity Values and Adjustment Factors from Large Customer Response Data

For each of the demand response programs and tariffs, we calculated elasticity values for each market segment using individual customer load and price data obtained from the data sources outlined in section 4.1. For the two hourly pricing tariffs, we estimated demand models to calculate substitution elasticities.⁶² For the other programs, data was only available during declared event hours, providing insufficient observations to estimate a fully specified demand model, so we calculated arc elasticities.⁶³ For the short-notice event program estimates, we pooled the observations from the New York Independent System Operator (NYISO) and ISO-New England (ISO-NE) emergency programs. Estimates for all other demand response options were derived from a single data source (see section 4.1). For each type of program and tariff, we calculated four sets of elasticity values (described below) to support the scenarios in section 4.4, which simulate market potential under a variety of assumptions.

4.3.1 Average Elasticity Values

For each program, we computed average elasticities for the customers in each market segment (see Table 4-4)⁶⁴.

4.3.2 Elasticities Adjusted for Onsite Generation

Ideally, a demand response market potential study should evaluate the impact of a variety of external and customer-specific factors on individual customer price experience. Unfortunately, very little information was available among our data sources on the factors identified as potential drivers in section 3.4.3 (see Table 4-5).

⁶² This was done as part of case studies conducted on the individual tariffs. For more details, see Goldman et al. (2005) and Boisvert et al. (2004).

⁶³ See section 3.4.1 for a discussion of tradeoffs in selecting elasticity measures. Substitution and arc elasticity values are not directly comparable, although the market potential impacts derived from them are.

⁶⁴ For the price response event program, a number of program events occurred when prices were quite low (\$100–150/MWh). Including observations from these low-price events resulted in extremely high average elasticities, because there was considerable variation in loads, but relatively small differentials between the event prices and the otherwise applicable (baseline) tariff rate. To remove this “noise” from the elasticity estimates, we restricted our analysis to observations in which the price was \$150/MWh or higher.

Table 4-4. Average Elasticity Values

Customer Market Segment	Demand Response Option				
	Optional Hourly Pricing	Default Hourly Pricing	Short-notice Emergency Program	Price Response Event Program	Critical-peak Pricing
Commercial/retail	0.01	0.06	-0.03	-0.09	-0.10
Government/education	0.01	0.10	-0.02	-0.16	-0.06
Healthcare	0.01	0.04	-0.04	-0.05	-0.01
Manufacturing	0.26	0.16	-0.04	-0.16	-0.05
Public works	0.07	0.02	-0.08	-0.22	-0.08

Note: Elasticity of substitution values are shown for optional and default hourly pricing and are typically positive; arc elasticity values are shown for all other demand response options and are typically negative.

Table 4-5. Availability of Data on External and Customer-Specific Factors

Factor	Demand Response Option				
	Optional Hourly Pricing	Default Hourly Pricing	Short-notice Emergency Program	Price Response Event Program	Critical-peak Pricing
EXTERNAL FACTORS					
Event duration, frequency & clustering			•	•	
Weather	•	•	•	•	
CUSTOMER-SPECIFIC FACTORS					
Business activity (market segment)	•	•	•	•	•
Customer size (peak demand)	•	•	•	•	•
Training, awareness & past experience		•	§		
Onsite generation		§	•		•
Enabling technologies		§	§		•
Electricity intensity		§	§		
Business or operational processes		§	§		•

§ Available for subset of customers

• Available for all customers

The most detailed and consistent information was available for the default hourly pricing tariff, which was the subject of an in-depth case study involving customer surveys designed to collect information on various factors (Goldman et al. 2005). However, the study found very few factors, aside from weather and customer business activity, with a statistically significant impact on price response. This may be, at least partly, due to sampling issues—customer-specific factors were only available for the subset of customers that answered the survey.

Both short-notice emergency programs, however, provided consistent and revealing information on the relationship between customer ownership of onsite generation and demand response. Customers in these programs with onsite generators had, on average, arc elasticities about 40% higher than customers that did not. From this information, we developed elasticity adjustment factors for the short-notice emergency program. For customers without onsite generation, the elasticities decline by 14% relative to the average elasticities for each market segment. For those with this technology, the elasticity values are 52% higher than the average (see Table 4-6). Applying these revised elasticity estimates to simulate market potential can result in either higher or lower estimates than are given by the average elasticities in Table 4-4, depending on the distribution of onsite generators among the target population relative to that from which the elasticities were estimated (see section 4.4.3).

Table 4-6. Elasticity Values Adjusted for Onsite Generation

Customer Market Segment	Short-notice Emergency Program	
	without DG	with DG
Commercial/retail	-0.03	-0.05
Government/education	-0.02	-0.03
Healthcare	-0.03	-0.05
Manufacturing	-0.04	-0.07
Public works	-0.07	-0.12

We did not apply this adjustment to the elasticity estimates for other demand response programs because it is only consistent with the usage of onsite generation for emergency demand response programs. For economic programs, customers' decisions to use onsite generation can be very different, often driven by economic rather than reliability criteria. There is anecdotal and empirical evidence that customers with onsite generation can be very responsive to optional hourly pricing tariffs (see, for example, Schwarz et al. 2002), but there is little information on the impact of onsite generation on response to other demand response options.

4.3.3 Elasticities Refined to Reflect Response at High Prices

In our market potential simulations in section 4.4, we estimate market potential assuming an "event" (or high hourly) price of \$500/MWh. This places the results on an equal footing for each of the programs. However, the customer load response data used to estimate the elasticities differed for each program and for some the customers faced a wide range of prices. Applying average elasticities derived from a range of price levels to estimate response to a specific price may be misleading if customers respond differently

at different price thresholds.⁶⁵ To test for this effect, we refined the elasticity estimates, computing them using only data at price thresholds comparable to the \$500/MWh price.

For the default hourly pricing option, substitution elasticities were developed using a flexible model that allowed for statistical evaluation of response at different price thresholds (see Goldman et al. 2005). We applied adjustment factors derived from this model to each market segment to develop elasticities tailored to response at high prices.⁶⁶

For the arc-elasticity values calculated from the demand response programs, we simply eliminated observations for which the event price was below \$450/MWh, and recomputed average elasticities for each sector and program from this smaller set of observations.

The resulting elasticity values are presented in Table 4-7. For the default hourly pricing tariff, commercial/retail and government/education customers increase their response at high prices. For manufacturing customers, there is no change in elasticity, and for the other sectors a slight decline in response is observed.

Table 4-7. Elasticities Based on Customer Response to High Prices (\$500/MWh)

Customer Market Segment	Demand Response Option			
	Default Hourly Pricing	Short-notice Emergency Program	Price Response Event Program	Critical-peak Pricing
Commercial/retail	0.10	-0.03	-0.02	-0.04
Government/education	0.16	-0.02	-0.02	-0.04
Healthcare	0.03	-0.04	-0.01	-0.00
Manufacturing	0.16	-0.04	-0.03	-0.03
Public works	0.01	-0.08	-0.02	-0.05

Note: Elasticity of substitution values are shown for optional and default hourly pricing; arc elasticity values are shown for all other demand response options.

Since very few of the observations for the two short-notice emergency programs involved event prices lower than \$450/MWh, the revised elasticity estimates are essentially unchanged.⁶⁷

⁶⁵ Statistically significant differences in customer price response at different prices were found by Goldman et al. (2005).

⁶⁶ The analysis of the optional hourly pricing tariff did not examine the effect of prices on response in detail, so we were unable to conduct this sensitivity analysis for this tariff.

⁶⁷ The program design of the NYISO EDRP program sets a floor price of \$500/MWh, so none of these observations were removed. ISO-NE's emergency program offers two floor-price options—\$500/MWh and \$250/MWh—depending on the amount of notice customers receive of impending events. Thus, only a few observations, corresponding to the lower floor-price option, were removed from the sample.

For the price response event program and critical-peak pricing, the elasticities decrease compared to the averages in Table 4-4 in all market segments. This occurs because these customers' load response was fairly consistent across the range of prices. Although this may seem counterintuitive, we believe that this result is consistent with our underlying conceptual framework of customer response which is based on the notion that many large business and institutional customers are only willing to curtail or forego load which they consider "discretionary," irrespective of price level. This means that arc elasticities computed when prices were high (with comparable load response but lower price differentials) result in lower elasticities than those computed at lower prices. Restricting the dataset to events with higher prices therefore results in lower average elasticities. This effect is relatively minor for the critical-peak pricing example, but is quite pronounced for the price response event program.

4.3.4 Elasticities Refined for Within-Sector Variation in Price Response

We also defined and estimated elasticities that account for differences in customer response *within* market segments.⁶⁸ For each market segment and program, we computed "low", "medium" and "high" elasticity values that reflect the observed distribution of customer response among our data sources. Each value represents the load-weighted average elasticity of a subset of customers within a given market segment, for a given program. For low values, all customers with elasticities less than 0.01 (absolute value) were included. The high values reflect the most responsive tenth percentile of customers in a particular market segment. The medium values are computed from the remaining customers.

In this way, we derived the low, medium and high elasticity estimates in Table 4-8. In some cases, there were too few customers to compute all three values (e.g., certain market segments are underrepresented in the optional hourly pricing tariff). In other cases, low values are not reported as there were no customers with elasticities below the 0.01 threshold (e.g., some market segments in the critical-peak pricing and price response event programs).

⁶⁸ Goldman et al. (2005) found a wide range in customer response within all large customer market segments.

Table 4-8. Low, Medium and High Elasticity Seed Values

Customer Market Segment	Demand Response Option								
	Optional Hourly Pricing			Default Hourly Pricing			Short-notice Emergency Program		
	low	medium	High	low	medium	high	low	medium	high
Commercial/retail	—	0.01	—	0.00	0.03	0.35	-0.00	-0.03	-0.16
Government/education	—	0.01	—	0.00	0.06	0.96	-0.00	-0.02	-0.17
Healthcare	—	0.01	—	0.00	0.04	0.05	-0.00	-0.03	-0.14
Manufacturing	0.00	0.29	0.99	0.00	0.06	0.56	-0.00	-0.05	-0.24
Public works	0.00	0.18	1.04	0.00	0.02	0.08	-0.00	-0.08	-0.31

Customer Market Segment	Demand Response Option					
	Price Response Event Program			Critical-peak Pricing		
	low	medium	High	low	medium	high
Commercial/retail	-0.00	-0.07	-0.66	-0.01	-0.07	-0.39
Government/education	-0.00	-0.13	-0.73	—	-0.04	-0.22
Healthcare	—	-0.03	-0.35	-0.00	-0.02	-0.03
Manufacturing	—	-0.14	-0.73	-0.01	-0.03	-0.28
Public works	—	-0.21	-0.70	—	-0.06	-0.18

Note: Elasticity of substitution values are shown for optional and default hourly pricing; arc elasticity values are shown for all other demand response options.

4.4 Putting it All Together: Market Potential Simulation Results

The final step in this simulation exercise was to apply the elasticity values to information on the customer population of an urban utility in the Northeastern U.S. (see the adjacent textbox) to develop market potential estimates. For the two hourly pricing options, we used formulas (5) and (6) in section 3.5 to calculate load impacts by market segment and customer size from the substitution elasticity values. For the other options, for which arc elasticity values were available, we used formulas (4) and (5) (also in section 3.5).

To estimate load impacts from substitution and arc elasticities, information or assumptions about expected loads (i.e., CBLs), and event and non-event prices are needed. For expected loads, we used

Overview of our Sample Utility

We selected an urban utility in the Northeastern U.S., for which we had access to large customer characteristics and usage data, to demonstrate market potential simulations.

The selected utility is relatively small; the peak demand of its large, non-residential customers is only ~1,700 MW. These customers represent about 40% of the utility's peak demand, and consist largely of commercial/retail, government/education and healthcare facilities. Manufacturing customers are less prevalent than for utilities that serve suburban or rural communities.

business-class specific load profiles derived from NMPC SC-3A customer data.

We also adopted a common and consistent set of assumptions for underlying retail rates and “event” prices in scenarios in order to evaluate demand response options and cases on an equal footing. We developed peak and off-peak tariff rates by customer size classification for a hypothetical utility (see Table 4-9).⁶⁹ We assumed the same “event” price of \$500/MWh (or 50¢/kWh) for all customers and programs. This is fairly typical of both the high prices observed in hourly pricing programs in recent years, and incentive floor prices offered by ISO emergency programs. Off-peak rates on event days (necessary to calculate load impacts from substitution elasticity values)⁷⁰ were scaled up from the off-peak tariff rates to reflect typically higher off-peak prices that accompany high on-peak prices in wholesale markets. The assumed peak period is from noon to 6:00 p.m.

Table 4-9. Prices Used in Market Potential Simulations

Customer Size (MW)	Tariff Rate (¢/kWh)		Event Day Prices (¢/kWh)	
	Peak ¹	Off-peak	Peak ¹	Off-peak
0.35–0.5	15.0		50.0	16.7
0.5–1	14.0		50.0	15.6
1–2	13.0		50.0	14.5
2–5	14.4	11.2	50.0	13.4
> 5	13.2	10.2	50.0	12.3

¹ The peak period is defined as 12:00 a.m.–6:00 p.m. All other hours are considered off-peak.

We developed five scenarios to demonstrate the effects of various factors on demand response market potentials and to evaluate the robustness of the substitution and arc elasticities to changes in the simulation inputs. The scenarios are as follows:

- *Base case*—uses average elasticity values by market segment and customer size, and participation rates developed in section 4.2, to estimate market potential;
- *Program participation*—demonstrates the impact of customer participation rates on market potential;
- *Onsite generation*—accounts for differences in elasticity for customers with and without onsite generation;
- *Response at High Prices*—uses elasticities that reflect customer response at high prices (above \$450/MWh); and

⁶⁹ We deliberately scaled the tariff rates to reflect typical differences in distribution rates among size classes, as well as the prevalence of single-block rates for smaller customers in the U.S.

⁷⁰ For the arc elasticity examples, only two price inputs are needed to calculate load impacts: an event price (peak-period event price in Table 4-9) and an otherwise applicable rate (peak-period tariff rate in Table 4-9). Estimating impacts from substitution elasticity values requires off-peak as well as peak prices for event and other days. See section 3.5 for more information.

- *Within-Sector Variation in Customer Response*—evaluates the impact of modeling a distribution of price responsiveness among the target customer population.

4.4.1 Base Case

We express demand response market potential estimates both in terms of direct MW savings and as a proportion of the non-coincident peak demand of the target population of large customers.⁷¹ The overall base-case results range from 0% to 3% of the peak demand for the target population of customers larger than 350 kW (see Table 4-10). The load reductions for the largest customers (>1 MW) enrolled in the default hourly pricing and price response event programs represent 5-6% of their aggregate peak demand. The highest market potential (3% of peak demand) corresponds to the default hourly pricing tariff. This is largely due to the relatively high customer acceptance rates for this tariff (see Table 4-3).

Table 4-10. Market Potential Results: Base Case

Customer Size (MW)	Optional Hourly Pricing		Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
	MW	% of class peak demand ¹	MW	% of class peak demand ¹	MW	% of class peak demand ¹	MW	% of class peak demand ¹	MW	% of class peak demand ¹
0.35–0.5	1.0	0%	2.8	0%	0.4	0%	1.6	0%	1.3	0%
0.5–1	1.1	0%	3.9	1%	4.3	1%	3.0	1%	1.7	1%
1–2	1.9	1%	14.4	6%	3.8	2%	3.9	2%	1.9	1%
> 2	21.6	4%	34.8	6%	11.5	2%	29.1	5%	2.4	0%
Total	25.6	2%	55.9	3%	19.9	1%	37.6	2%	7.3	0%

¹ Peak demand is non-coincident.

Note: Each demand response option was evaluated separately—the results are not additive.

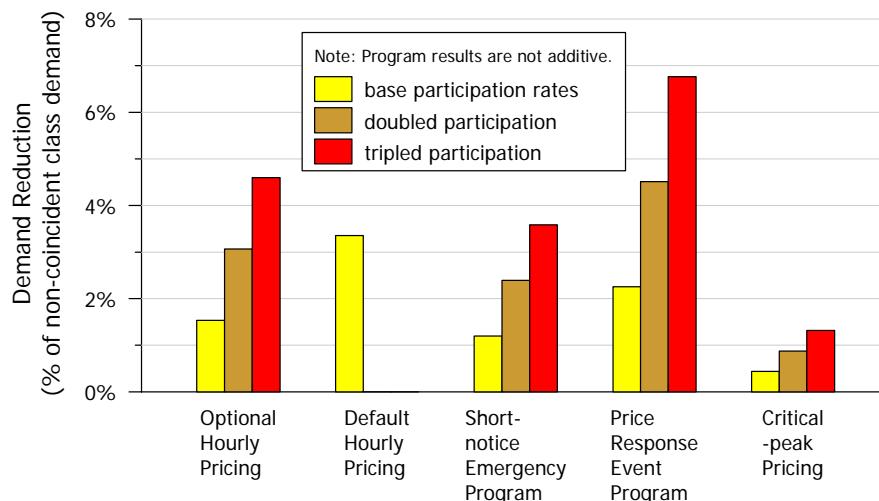
4.4.2 Impact of Participation Rates

Market assessments often examine the impact of differing rates of participation on program potential. In Figure 4-1, we illustrate the impact of aggressively marketing programs to customers so as to achieve two and three times the base-case participation rates (which reflect the experience of the demand response programs used as data sources). Considering that participation rates of double or triple the current experience are indeed aggressive, the results, in the order of 3–6 percent of non-residential peak demand, can be viewed as an approximate upper bound on market potential for each type of demand response option among large C&I customers. For default hourly pricing,

⁷¹ We did not have class-level peak demand for the Northeastern utility, only customer-level peak demand. To approximate class peak demand, we added the individual customer peak demands. Because not all customers' peak demand occurs at the same time, this overestimates the actual class peak (and therefore under-estimates the load impacts).

which by definition would not be marketed to customers, we do not show enhanced participation, although the base case results are included in the figure for comparison.

The results in Figure 4-1 were calculated using the same elasticities and other inputs as the base case—only the participation rates vary. The embodied assumption is that the additional enrolled customers are just as responsive to price signals or emergencies as the relatively “early adopters” observed among our data sources. In reality, it may be that the most responsive customers are also the first to sign up, leading to declining average elasticities as more customers are enrolled. On the other hand, strategies that combine program marketing with technical assistance to develop fully automated demand response could enhance both participation rates and response to prices or emergencies. An automated demand response pilot in California with a sample of ~30 medium and large commercial, institutional, and high-tech buildings demonstrated this potential, achieving consistent average load curtailments of ~10% with high customer satisfaction (Piette et al. 2005; CPUC 2006a). However, there is currently no large-scale program experience to confirm or refute these possibilities.



Note: The level of demand response (elasticity) is assumed to be the same for all scenarios—this assumption has yet to be evaluated with actual program experience.

Figure 4-1. Impact of Program Participation Rates on Demand Response Market Potentials

4.4.3 Accounting for Onsite Generation

We examined the impact of refining and disaggregating the elasticity estimates for the short-notice emergency program to account for differences in response by customers with and without onsite generation technology.⁷² On average, customers in this program with onsite generation had arc elasticities about 40% higher than those customers that did not. Interestingly, this resulted in slightly lower market potential estimates than the base case

⁷² We limited this case to the short-notice emergency program due to data limitations. For other demand response options, little information is currently available on the impact of onsite generation on customer response.

(i.e., 17.6 versus 19.9 MW) (see Table 4-11). This is due to differences in our assumptions about the distribution of onsite generators among the customer population at the representative urban utility compared to the observed distribution among the customers from whom the elasticity estimates were estimated.⁷³ For a utility with a higher relative penetration of onsite generation technologies, this refinement would yield higher market potential results than the average elasticities provide.

Table 4-11. Market Potential Results: Onsite Generation

Customer Size (MW)	Short-notice Emergency Program	
	MW	% of class peak dmd ¹
0.35–0.5	0.3	0%
0.5–1	3.7	1%
1–2	3.4	1%
> 2	10.2	2%
Total	17.6	1%

¹ Peak demand is non-coincident.

Although the overall market potential estimates are comparable in our example, understanding differences in the underlying elasticities among customers with and without enabling technologies can help policymakers target programs to customers that are likely to be the most responsive (e.g. those with on-site generation equipment). Furthermore, research suggests that onsite generation can improve the consistency, as well as the degree, of customer response.⁷⁴

4.4.4 Accounting for Response at High Prices

In this scenario, we refined the elasticity estimates of four of the program types to better reflect customer response at the \$500/MWh event price assumed for these simulations. Comparing the results in Table 4-12 with the base case (Table 4-10) reveals that for the default hourly pricing program, accounting for differences in response at higher prices results in higher market potential (i.e., 74 versus 55 MW). This result is driven by the fact that customers in certain market segments (government/education and commercial/retail) were more price-responsive at higher prices and our illustrative utility had a high proportion of these types of customers.

⁷³ Detailed information on the distribution of onsite generators among the Northeast utility's customers was not available. To perform the simulation, we developed onsite generation penetration rates using data from EIA's Commercial Building Energy Consumption Survey (EIA 2003) and Manufacturing Energy Consumption Survey (EIA 2002).

⁷⁴ NYISO EDRP customers with onsite generation provided actual load reductions that were closer to their subscribed load than those without (Neenan et al. 2003).

Table 4-12. Market Potential Results: Response at High Prices

Customer Size (MW)	Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
	MW	% of class peak demand ¹	MW	% of class peak demand ¹	MW	% of class peak demand ¹	MW	% of class peak demand ¹
0.35–0.5	4.1	1%	0.4	0%	0.3	0%	0.7	0%
0.5–1	5.7	2%	4.2	1%	0.5	0%	1.0	0%
1–2	19.2	8%	3.7	2%	0.7	0%	1.0	0%
> 2	45.3	8%	11.1	2%	5.1	1%	1.3	0%
Total	74.2	4%	19.4	1%	6.6	0%	4.1	0%

¹ Peak demand is non-coincident.

Note: Each demand response option was evaluated separately—the results are not additive.

In contrast, for the price response event program and critical-peak pricing, restricting observations to only high-price events resulted in lower average arc elasticities in all market segments (see Table 4-7). The arc elasticity values are lower for these options because participating customers provided roughly the same amount of load reduction at low prices (~\$200/MWh) as they did at \$>450/MWh (i.e., the percentage change in load remains the same during the high price event hours, while the percentage change in price increases). As a result, the market potential estimates are lower for these two programs than the base case that used average elasticities across all observed prices.⁷⁵ Because the short-notice emergency program elasticities were virtually unchanged (see section 4.3.3), the difference in market potential relative to the base case is negligible.

This scenario demonstrates the limitations of arc elasticities in accounting for influences other than price on customer load changes. Because only prices and load at a single event are captured in estimating arc elasticities, there is no way to account or correct for noise in the estimates (i.e. other factors that drive changes in customer usage). At higher prices, we believe that changes in load are more likely a result of prices rather than other factors. When arc elasticities are used, it is therefore important to be cognizant of these limitations and ensure that observations are drawn from conditions similar to those under simulation.

4.4.5 Accounting for Within-Sector Variations in Customer Response

Our final scenario examines the impact of accounting for differences in customer response within market segments. By assigning low, medium and high elasticities to proportions of the customers in each market segment defined by observed elasticity distributions among customers, we developed the results in Table 4-13.

⁷⁵ Even in the base case, however, we restricted observations for the price response event program to prices greater than \$150/MWh, as estimates at lower prices resulted in inordinately high elasticities due to large changes in load relative to the small price differential.

Overall, this contributes to lower market potential estimates for all programs compared to the base case (see Table 4-10). With very few exceptions, this is true for customer size classes within programs as well. Several studies of large customer price response have found that most of the observed aggregate load response is attributable to a small number of very price-responsive customers, with other customers contributing more modest curtailments or none at all.⁷⁶ Accounting for this distribution, rather than assuming average elasticities across the board, more accurately depicts actual load impacts.

Table 4-13. Market Potential Results: Response Distribution Effects

Customer Size (MW)	Optional Hourly Pricing		Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
	MW	% of class peak demand ¹	MW	% of class peak demand ¹	MW	% of class peak demand ¹	MW	% of class peak demand ¹	MW	% of class peak demand ¹
0.35–0.5	0.8	0%	3.0	1%	0.5	0%	1.6	0%	1.2	0%
0.5–1	0.9	0%	4.1	1%	5.7	2%	2.9	1%	1.8	1%
1–2	1.8	1%	13.6	6%	3.6	2%	3.5	1%	2.4	1%
> 2	14.3	3%	26.4	5%	14.2	3%	24.2	5%	0.9	0%
Total	17.8	1%	47.1	3%	23.9	1%	32.3	2%	6.4	0%

¹ Peak demand is non-coincident.

Note: Each demand response option was evaluated separately—the results are not additive.

4.5 Summary: Discussion

The results of our simulations illustrate possible ranges of demand response market potential for large commercial and industrial customers at an urban Northeast utility, as well as several key methodological and data issues. These stylized results are specifically tied to and reflect the characteristics of this urban utility’s large customer base as well as the specific assumptions we made about prices and other factors in this simulation. As such, they should not be taken as definitive estimates of market potential in general and should certainly not be translated directly to other utilities or jurisdictions. Nonetheless, we draw the following insights and conclusions from our scoping study of demand response market potential.

First, we believe that the results provide an indication of a reasonable range of the demand response market potential of non-residential customers if offered similar demand response options by other similar utilities. The aggregate load reductions for our urban, Northeast utility ranged from 7 to 55 MW for each demand response option, representing about <1 to 3% of the peak demand of the target population of large customers. In interpreting the relatively small aggregate load reductions obtained from large customers in specific programs, we note that it may not be necessary for demand response resource

⁷⁶ See, for example, Braithwait and Armstrong (2004), Goldman et al. (2005), and Schwarz et al. (2002).

options to achieve their full technical potential or very high participation rates in order to provide optimal value to a power system.

Second, the simulations illustrate the relative impact of certain factors, particularly customer participation rates, on aggregate load reduction that could be achieved among the target population of large customers. It is worth noting that participation rates currently represent the largest data uncertainty for analysts undertaking market potential studies. Clearly, there is a need for systematic collection and reporting of information on the eligible target population (by market segment) as well as a better understanding of the drivers for participation in various demand response programs and customer acceptance of dynamic pricing tariffs.

Third, the scenarios also demonstrate the importance of refining and disaggregating elasticity estimates for different groups of customers rather than simply applying average values. In several cases, this resulted in *lower* market potential estimates in our simulations. Policymakers considering establishing demand response goals need to be cautious; as goals extrapolated from pilot programs or demand response potential study estimates based only on small samples of very responsive customers may not be achievable.

Fourth, the simulation results demonstrate that arc elasticities, though in some cases necessary due to data limitations, are more sensitive to changes in assumptions than substitution elasticities. The additional resources necessary to derive elasticities from theoretically based demand models are well worth the added confidence they afford to market potential studies and market assessments on which important policy decisions may be based.

Finally, we emphasize that all demand response market potential studies should examine a range of scenarios—not limited to those demonstrated here—in estimating the potential of demand response options to deliver load reductions when needed. Each jurisdiction should evaluate factors that may drive local market potential and, to the extent possible, represent them in market potential studies.

5. Advancing the State of the Art: A Market Assessment Research Agenda

In this study, we have described and demonstrated a methodology that is well suited to modeling the market potential of large-customer demand response options that rely on customer-initiated actions in response to dynamic prices or financial incentives. We have also provided program participation rate and elasticity values that can be used as a starting point for demand response market assessments.

However, this information is based on a limited set of programs, and a number of key methodological and data constraints limit their usefulness for demand response market potential studies and assessments. Moreover, no individual state or utility will have the resources or the access to information to fill in all the gaps.

In this section, we present a market assessment research agenda that highlights specific gaps in the current state of knowledge about customer participation in and response to demand response options as well as areas where methodologies are not well developed. Addressing these gaps will involve evaluating the experience of existing programs and tariffs and compiling results in a consistent and publicly available format so that they are available to a broad audience.

With this in mind, we recommend that state and federal policymakers and regulators encourage utilities, other load serving entities, ISOs/RTOs, program evaluators and analysts to conduct the following activities:

1. **Link Program Evaluation to Market Potential Studies:** *Evaluations of demand response programs should systematically collect data on the characteristics of participating customers; hourly customer loads, prices, and response; other factors found to be relevant drivers of customer participation and response; and information on the size and characteristics of the target or eligible population.*

For this report, we had access to customer-level information for several established demand response programs offered to large non-residential customers. To develop a broader base of information on customer participation rates and demand response, there is a need for continued data collection from existing as well as new demand response programs.

To support future analyses of program participation, **utilities (and possibly ISOs/RTOs)** should provide information on both customer enrollment and the eligible customer population (numbers of customers and amount of load), so that accurate participation rates can be calculated.⁷⁷

⁷⁷ Several of the data sources used in this study did not have information on the eligible customer population, making it difficult to develop realistic program participation rate estimates (see section 4.2).

In terms of customer characteristics, **demand response program administrators and evaluators** should collect, at a minimum, information on customer size (i.e. peak demand for large customers) and market segment.⁷⁸

To support estimation of price elasticities, customer loads and prices are needed, preferably on an hourly basis. In addition, customer characteristics—at a minimum, data on customer market segments and availability of enabling technologies such as onsite generation—are needed, along with other factors found to be relevant drivers of customer participation and demand response.

Regulators and policymakers responsible for authorizing new demand response programs and tariffs should ensure that adequate data collection practices are included in program administration and evaluation.

2. **Program Participation:** *Develop predictive methods for estimating participation rates in demand response programs and dynamic pricing tariffs that incorporate customer characteristics and other factors that drive participation. Where applicable, include interactive effects of multiple program offerings in estimating market penetration rates.*

Of all the steps involved in estimating demand response market potential, methodologies (and data) for estimating program participation are the least well established. However, program participation is perhaps the most important variable determining the aggregate market potential of demand response programs and tariffs. Existing studies (this one included) have either assumed penetration rates based on “expert judgment” or have directly applied observed participation rates without adjustment for factors that might drive them. There is also a need to better understand customers’ participation decisions when faced with multiple demand response options, whether offered on an “either-or” or complementary basis.

To address this, **program evaluators and analysts** should develop predictive models from observed customer participation rates that account for customer- and market-specific factors that drive response, including interactions between multiple program offerings. The development of better methods, along with the addition of more data sources, will enable more defensible estimates of market potential under a range of circumstances.

3. **Price Response:** *Estimate price elasticity values for different market segments, accounting for the relative impact of driving factors, and report methods and results transparently. Where possible, estimate demand or substitution elasticities, using fully specified demand models, rather than arc elasticities. Where applicable, account for the effects of customer enrollment and participation in multiple demand response offerings.*

⁷⁸ Market segment information may consist of SIC codes or other information on business activity for large customers.

As more data on pilot and full-scale demand response programs and tariffs become available, elasticity estimates should be refined to reflect both a larger body of experience and improved understanding of the drivers of price response. Where feasible, **program evaluators** should estimate the price response of customers using fully specified demand models that can account for interactions among factors driving response.⁷⁹ Understanding the diversity of customer circumstances and behavior, across markets and over time can be key to realizing the full benefits of demand response. Information from customers that simultaneously participate in multiple demand response options (e.g., customers on default hourly pricing that participate in emergency programs) should be used to improve the understanding of program interactions on customer demand response, allowing market potential studies to model interactive effects.

4. **Assess the impacts of demand response enabling technologies:** *For large customers, there is a need to document the impacts of specific demand response enabling technologies on customer participation and load response, given limited evidence and mixed results from existing evaluations.*

The current understanding of the impacts of enabling technologies on demand response is somewhat rudimentary, partly because past evaluations have collected limited information on the presence of these technologies, and partly because many of them are at an early stage of market penetration and customer awareness of their demand response applications is low.⁸⁰

Demand response program administrators should consider gathering information on the availability and use of *demand-response enabling technologies* among customers, through some combination of utility or third-party surveys, and deployment statistics from technology incentive and/or technical assistance programs. We also recommend that **program evaluators** obtain information on customers' load curtailment strategies that involve onsite generation,⁸¹ peak load controls, energy management control systems, energy information systems, and other demand response enabling technologies disseminated as part of technical assistance programs.

5. **Publicize Results:** *Explore ways to pool customer-level data, while protecting customer confidentiality, so that information to support demand response market assessments is available in a standardized format.*

⁷⁹ Depending on the program design, call-type programs offered to customers on flat rate electricity tariffs may not expose customers to a wide enough range of prices to support estimation of a demand model. In such cases, arc elasticities may be estimated, but analysts should exercise caution in interpreting the results (see section 4.4.4).

⁸⁰ For example, Goldman et al. (2005) had to collect information on enabling technologies through customer surveys, and the response rates limited the number of customers for whom enabling technology impacts could be measured. The same study found that many customers that owned technologies with the potential to assist with price response in fact used them for other purposes.

⁸¹ Information on diesel-fired emergency back-up generators should be tracked separately from cogeneration, combined heat and power, and other distributed energy technologies.

Currently, information on customer participation in and response to demand response programs and dynamic pricing tariffs is spread across a variety of program evaluation and case study reports. The results and methods are not standardized, nor are they, in many cases, transparent. This report has attempted to address this problem by compiling individual customer data from a number of demand response program evaluations targeted at large customers.

Going forward, **ISOs, RTOs, utilities** and **state and federal policymakers** should explore ways to pool the results of various demand response program evaluations in a standardized format, so that customer-specific information, appropriately masked, can be aggregated to develop improved program participation and elasticity estimates. The results of such efforts should be made available to assist with market assessment activities.

If implemented, these recommended activities will produce more detailed and robust price response and participation rate values that can be used by utilities and states undertaking demand response market assessment activities in their service territories or regions. However, in order to make best use of this information, utilities, ISOs, and states will need disaggregated information on the characteristics of their target population of customers (e.g., customer loads by size range, market segments, enabling technology deployment) in order to apply these values to their local area. In some cases, this information is not typically collected by utilities on their customers. Therefore, we recommend that **states, utilities and their consultants** conducting demand response market assessments first assess the current availability of information on customer characteristics and usage in their jurisdictions and include plans to collect or estimate any necessary incremental information in their study plans and budgets.

References

- 2006. “National Action Plan for Energy Efficiency”, July. Available online: <http://www.epa.gov/cleanenergy/actionplan/report.htm>
- Braithwait, S. and D. Armstrong, 2004. “Potential Impact of Real-time Pricing in California”, report to the California Energy Commission (CEC), January 14.
- Braithwait, Steven and Michael O'Sheasy, 2001. “RTP Customer Demand Response – Empirical Evidence on How Much You Can Expect”, Chapter 12 in *Electricity Pricing in Transition*, A. Faruqui and K. Eakin, editors, Kluwer Academic Publishers.
- Boisvert, Richard, Peter Cappers, Bernie Neenan and Bryan Scott, 2004. “Industrial and Commercial Customer Response to Real Time Electricity Prices”, December, available online at <http://eetd.lbl.gov/ea/EMS/drlm-pubs.html>.
- Brown, M., 2001. “Market failures and barriers as a basis for clean energy policies” *Energy Policy* 29(4): 1197-1207.
- California Public Utilities Commission (CPUC), 2004. Decision 04-09-060, “Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond,” September 23, 2004.
- California Public Utilities Commission (CPUC), 2006a. “Assigned Commissioner’s Ruling Augmenting August 6, 2006 Ruling Requiring Utility Proposals to Augment 2007 Demand Response Programs”, August 22, 2006.
- California Public Utilities Commission (CPUC), 2006b. Agenda 05-06-006 et al., “Order Adopting Changes to 2007 Utility Demand Response Programs,” October 30, 2006.
- Caves, D., L. Christensen and J. Herriges, 1984. “Consistency of Residential Response in Time of Use Pricing Experiments”, *Journal of Econometrics* 26(1984):179-203.
- Charles River Associates, 2005. “Impact Evaluation of the California Statewide Pricing Pilot”, final report to the California Energy Commission, March 16.
- Charles River Associates (Asia-Pacific) Pvt. Ltd and Gallagher & Associates, 2001. “Electricity Demand Side Management Study: Review of Issues and Options for Government”, Prepared for VENCORP, Melbourne, Australia, September 7.
- EFFLOCOM, 2004. “Energy Efficiency and Load Curve Impacts of Commercial Development in Competitive Markets”, report to SINTEF, April 8.
- Energetics, 2000. “Epping/North Ryde Demand Side Management Scoping Study: Identifying Opportunities for DSM to defer Electricity Network Investment in Northwestern Sydney”, report to Sustainable Energy Development Authority and Energy Australia, April 1.

Energetics, 2005. “Demand Management Investigation: Investigation of the Potential to Reduce Electricity Demand in the Sutherland and St. George Regions of Sydney”, report to the Demand Management and Planning Project, Australian Department of Infrastructure, Planning & Resources, Energy Australia and TransGrid, May.

Energy Information Administration (EIA), 2002. *Manufacturing Energy Consumption Survey (MECS)*, <http://www.eia.doe.gov/emeu/mecs/contents.html>

Energy Information Administration (EIA), 2003. *Commercial Building Energy Consumption Survey (CBECS)*, <http://www.eia.doe.gov/emeu/cbecs/>

Energy Information Administration (EIA), 2005. *Form EIA-861 Database* <http://www.eia.doe.gov/cneaf/electricity/page/eia861.html>

EPACT, 2005. *U.S. Energy Policy Act of 2005*, Public Law 109-58, August 8.

EPRI Solutions Inc., 2005. “Demand Response Analysis and Tool Development for Industrial, Agricultural, and Water Energy Users”, report to the California Energy Commission (CEC), September.

Goldberg, Miriam L., and G. Kennedy Agnew, 2003. “Protocol Development for Demand Response Calculation—Findings and Recommendations”, report to the California Energy Commission: CEC 400-02-017F, February.

Goldman, C., N. Hopper, O. Sezgen, M. Moezzi, R. Bharvirkar, B. Neenan, R. Boisvert, P. Cappers, and D. Pratt, 2004. “Customer Response to Day-ahead Wholesale Market Electricity Prices: Case Study of RTP Program Experience in New York”, report to the California Energy Commission, Lawrence Berkeley National Laboratory: LBNL-54761, June.

Goldman, Charles, Nicole Hopper, Ranjit Bharvirkar, Bernie Neenan, Richard Boisvert, Peter Cappers, Donna Pratt, and Kim Butkins, 2005. “Customer Strategies for Responding to Day-Ahead Market Hourly Electricity Pricing”, report to the California Energy Commission, Lawrence Berkeley National Laboratory: LBNL-57128, August.

Golove, W. and J. Eto, 1996. “Energy Efficiency, the Free Market and Rationales for Government Intervention” Paper presented to (De)Regulation of Energy: Intersecting Business, Economics, and Policy Conference, Boston, MA, October 27-30.

Gunn, Randy, 2005. “Estimating Demand Response Market Potential”, report to International Energy Agency Demand Side Management (IEA DSM) Programme: Task XIII Demand Response Resources, July.

Haeri, Hossein and Lauren Miller Gage (2006). “Demand Response Proxy Supply Curves”, report to Pacificorp, September 8.

Instituto Ingenieria Energetica, 2004. “End-User Acceptance And Potential For Demand Response”, Spain, July.

Jaffe, A. and R. Stavins, 1994. "The energy-efficiency gap: What does it mean?" *Energy Policy* 22(10): 804-810.

King, K. and P. Shatrawka, 1994. "Firm Response to Real-Time Pricing in Great Britain", in the proceedings of the American Council for an Energy Efficient Economy (ACEEE) 1994 Summer Study on Energy Efficiency in Buildings, Panel 2: Demand and Load Shapes, pp. 2194-2203.

Kubler, Jon, 2006. Personal communication, Georgia Power Company.

Levine, M., J. Koomey, J. McMahon and A. Sanstad, 1995. "Energy efficiency policy and market failures" *Annual Review of Energy and the Environment* 20: 535-555.

Momentum Market Intelligence, 2005. "Post-SPP Rate Choice Assessment Research: Final Report", presentation to the California Energy Commission, June.

Neenan, B., D. Pratt, P. Cappers, R. Boisvert, and K. Deal, 2002. "NYISO Price-Responsive Load Program Evaluation Final Report-Update", report to the New York Independent System Operator, February 8.

Neenan, B., D. Pratt, P. Cappers, J. Doane, J. Anderson, R. Boisvert, C. Goldman, O. Sezgen, G. Barbose, R. Bharvirkar, M. Kintner-Meyer, S. Shankle and D. Bates, 2003. "How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance", report to the New York Independent System Operator (NYISO) and New York State Energy Research and Development Agency (NYSERDA), January.

Piette, M.A., D.S. Watson, N. Motegi, and N. Bourassa, 2005. "Findings from the 2004 Fully Automated Demand Response Tests in Large Facilities", LBNL-58178, September.

Quantum Consulting, Inc. and Summit Blue Consulting, LLC, 2004. "Working Group 2 Demand Response Program Evaluation: Non-participant Market Survey Report", report to Working Group 2 Measurement and Evaluation Committee, August 5.

Quantum Consulting, Inc. and Summit Blue Consulting, LLC, 2006. "Evaluation of 2005 Statewide Large Non-residential Day-ahead and Reliability Demand Response Programs: Final Report", report to Southern California Edison Company and Working Group 2 Measurement and Evaluation Committee, April 28.

RLW Analytics and Neenan Associates, 2003. "An Evaluation of the Performance of the DR Programs Implemented by ISO-NE in 2003", report to ISO-NE Inc., December 30.

RLW Analytics and Neenan Associates, 2004. "An Evaluation of the Performance of the DR Programs Implemented by ISO-NE in 2004", report to ISO-NE Inc., December 29.

RLW Analytics and Neenan Associates, 2005. "An Evaluation of the Performance of the DR Programs Implemented by ISO-NE in 2005", report to ISO-NE Inc., December 30.

Rufo, Michael and Fred Coito, 2002. “California Statewide Commercial Sector Energy Efficiency Potential Study: Final Report,” July. www.calmac.org.

Sanstad, A., and R. Howarth, 1994. “‘Normal’ markets, market imperfections and energy efficiency” *Energy Policy* 22(10): 811-818.

Sanstad, A., W. M. Hanemann, and M. Auffhammer, 2006. “The California Climate Change Center at UC Berkeley, 2006. Managing Greenhouse Gas Emissions in California”, Chapter 6 in *End-Use Energy Efficiency in a “Post-Carbon” California Economy*, W. Michael Hanemann and Alex Farrell (Project Directors), January.

Schwarz, P. M., T. N. Taylor, M. Birmingham and S. L. Dardan, 2002. “Industrial Response to Electricity Real-Time Prices: Short Run and Long Run” *Economic Inquiry* 40(4): 597-610.

Southern California Edison (SCE), 2003. “Southern California Edison Company’s Long-Term Resource Plan Testimony—Appendices”, CPUC Application No. R. 01-10-024, Exhibit No. SCE-L-1, April 15.

Train, K., 1993. *Qualitative Choice Analysis: Theory Econometrics, and an Application to Automobile Demand*, MIT Press: Cambridge MA.

U.S. Department of Energy (DOE), 2006. “Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them” Report to Congress, February.

Violette, Dan, R. Freeman and C. Neil, 2006. “DRR Valuation and Market Analysis: Volume 1: Overview,” January. Available online: <http://www.demandresponseinfo.org/id80.htm>

Voytas, Rick, 2006. “AmerenUE Critical Peak Pricing Pilot”, presentation, July 26, Available online: <http://drrc.lbl.gov/pubs/drtown-pricing-voytas.pdf>

Western Governors’ Association Clean and Diversified Energy Advisory Committee (WGA CDEAC), 2006. “Energy Efficiency Task Force Report”, January. Available online: <http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency.htm>

Appendix A. Review of Methods for Estimating Demand Response Potential

A number of studies and tools have attempted to estimate demand response potential in recent years. In this Appendix, we summarize seven recent examples that have targeted large C&I customers. The methodologies used in these studies and tools can be broadly classified into four categories: customer-survey-based methods, benchmarking methods, engineering approaches, and elasticity approaches. These approaches are defined in section 2.2.

Customer Surveys

Among the reviewed studies, only an evaluation of California's large customer demand response programs adopted a customer-survey-based approach (Quantum and Summit Blue 2004). In this study, Quantum Consulting Inc. (now Itron) and Summit Blue Consulting LLC conducted a quantitative telephone survey of 500 non-participants. The ensuing market potential estimates were not independently confirmed with on-site engineering analyses. Nineteen percent of the respondents indicated some likelihood that they would participate in one of the programs, and another ten percent said they were "highly" likely to participate. The survey results suggest a total market potential of 1,200 to 1,800 MW with an average technical potential of 16 percent of coincident peak demand. Further, most customers said they would be willing to consider taking specific demand response actions on a limited number of hot summer afternoons. The survey responses also suggested significant demand response potential across all eligible size groups, including the smallest customers (100-200 kW range).

Benchmarking

One of the reviewed studies adopted a benchmarking approach. As part of the International Energy Agency Demand Response Resources project, Gunn (2005) conducted a survey of 40 North American utilities' experience with demand response programs that included questions about the types of demand response programs offered, participation in demand response programs, and the amount of load curtailed. Based on this survey, benchmarks for demand response potential were developed. These benchmarks were based on best-in-class demand response programs as identified through the survey of 40 North American utilities. The benchmarks developed for programs targeted to C&I customers are as follows:

- Interruptible/Curtailable:
 - Benchmark: 10% peak-load reduction
 - 17% of utilities report peak reductions greater than 15%—mainly from steel plants
 - 11% report reductions of 10–14%
 - ~50% report reductions of less than 4%
 - On average, the surveyed I/C programs had been in operation for 24 years
 - Larger reductions were reported by vertically integrated utilities than for utilities in areas with organized wholesale markets and ISOs/RTOs

- The highest reported participation rate was ~2% of C&I customers—most attributed low participation to restrictive eligibility criteria
- Demand Bidding:
 - Benchmark: 8-9% of utilities' C&I peak demand
 - Achieved in the past when prices were more volatile and higher
 - 67% of the utilities reported demand reduction impacts of 3% of their C&I peak demand or less
 - 20% of the utilities reported program impacts of 4%-7% of their C&I peak demand

The survey did not yield sufficient data to develop benchmarks for other demand response options such as critical-peak pricing, time-of-use rates, and real-time pricing.

Using these benchmarks, the project developed an online demand response potential calculator that provides a basic estimate of the available market potential in a given marketplace. For large C&I customers, demand response potential is estimated only for interruptible rates and demand bidding programs. The calculator uses demand response product benchmark performance information gathered from the International Energy Agency's Demand-Side Management Program Task XIII as a proxy for demand response market penetration (Gunn 2005). It then translates this proxy to the local (or target) market based on some simple user inputs:

- Number of C&I customers
- By program type:
 - System Peak Demand (MW)
 - C&I Sector % of system peak demand
 - Percent of C&I customers eligible for program
 - Average load reduction per participant customer (MW)
 - Current demand response product (MW)

Two estimation methods are presented. The first simply applies the 10% of C&I peak demand benchmark developed from North American interruptible rate and demand bidding programs. The second allows the user to input the following program parameters:

- the total number of C&I customers in their area
- the percentage of customers eligible for the demand response programs, and
- the average impact per customer.

The calculator estimates demand response potential assuming long-term program participation rates of 10% for demand bidding and 25% for interruptible rate programs.

Engineering Approaches

A number of analysts have adopted engineering approaches to estimate demand response potential. We found four such examples, which are described below. None of these

models is currently available in the public domain, and detailed documentation on the precise methods used is similarly unavailable.

The work described below represents the most recent engineering-based approaches adopted to study demand response market potential in the U.S. Studies conducted in Australia (Charles River Associates and Gallagher & Associates 2001, Energetics 2000 and 2005), Spain (Instituto Ingenieria Energetica 2004), and Europe (EFFLOCOM 2004) provide additional examples of engineering approaches for estimating demand response market potential.

DRPro™ Model

Quantec, LLC's DRPro™ model is a proprietary MS Excel-based model for estimating technical and market (achievable) demand response potentials (Haeri and Gage 2006). It is based on a hybrid top-down/bottom-up approach. For each demand response program type, the model begins by disaggregating loads into appropriate customer classes, market segments and end uses. Technical potential is then estimated at a gross level, assuming that all customer load sectors are potentially available for curtailment, except for those that clearly do not lend themselves to interruption. Market potential is then determined as the fraction of the technical potential that may be expected to be available for curtailment subject to customers' response to the program (program participation rates) and curtailment events (event participation rates).⁸² Program and event participation rates are assumed to be dependent on program type, customer characteristics, incentive levels (for load response), and price elasticities (for price response).

Data requirements of DRPro™ include demand response program information (options and strategies, applicable customer classes, eligibility requirements), utility data (hourly system load profile, customer class load shapes, sales by customer class, end-use load profiles, customer count by class and load size, costing periods), and market data (market or avoided utility capacity and energy costs, expected program and event participation rates). The methodology consists of the following steps:

1. **Define customer sectors, market segments, and applicable end uses.** The first step involves defining appropriate sectors, market segments, and end uses within each segment.
2. **Screen customer segments and end uses for eligibility.** This step involves screening of market segments and end uses for applicability of specific demand response strategies. For example, the hospital segment and certain commercial end uses, such as cooking loads in the restaurant segment, may be excluded.
3. **Compile utility-specific sector/end-use loads.** Load profiles are developed for each end use within various market segments of each utility. Contributions to system peak for each end use are then estimated based on end-use shares derived from end-use load shapes.

⁸² Event participation rates vary by program type and may approach 100% for DLC.

4. **Estimate technical potential.** Technical potential for each demand response program is assumed to be a function of customer eligibility in each class, affected end uses in that class, and the expected impact of the strategy on the targeted end uses. Analytically, technical potential (TP) for a demand-response program s is calculated as the sum of impacts at the end-use level (e), generated in customer class (c), by the program, according to the formulae:

$$TP_s = \sum TP_{sce}$$

and

$$TP_{sce} = LE_{cs} \times EUS_{cse} \times LI_{se}$$

where LE_{cs} (load eligibility) represents the percent of customer class loads that are eligible for strategy s , EUS_{cse} represents the share of end use e in customer class c eligible for demand-response strategy s , and LI_{se} (load impact) is the percent reduction in end-use load e resulting from program s . Load eligibility thresholds are calculated in terms of the percent of the load by customer class and market segment that meets minimum (or maximum) load criterion for each program based on program filings.

5. **Estimate Achievable Potential.** Achievable potentials for each program s are derived primarily by adjusting technical potentials by two factors: expected rates of program and event participation. Achievable potential (AP) is thus calculated as the product of technical potential (TP), program participation rates (PP), and expected event participation (EP) rates:

$$AP_s = \sum TP_{sce} \times PP_s \times EP_s$$

The resulting estimates of achievable potentials are then adjusted for load reductions achieved already by various programs, and applicable resource interactions to avoid double counting.

Estimates of program and event participation rates are generally derived based on benchmarking, past experience or expert opinion through a “Delphi” method. For price response programs, event participation rates are determined using price elasticities for various programs.

DRPro™ also offers the capability to simulate program and event participation rates under alternative scenarios using a Monte Carlo simulation technique. The model has been used in assessing demand response potentials for Puget Sound Energy, PacifiCorp, Portland General Electric, Aquila Networks, and Duke Energy.

Bass Diffusion Curve Model

XENERGY (now KEMA) used an “expert elicitation” approach to develop model parameters for its Bass Diffusion Curve Model (Gunn 2005). The modeling team used the professional judgment of a panel of experts to reach a consensus on key inputs to the supply curve model based on their experience in designing, managing, and evaluating demand response programs. This model was used to estimate the demand response

potential for a time-of-use type program in Southern California Edison (SCE)'s service territory.

Demand response potential was estimated using a series of demand response supply curves that varied by program type and market segment. A Bass Diffusion Curve, populated with electricity usage data by market segment and time period, was used to forecast the amount of load that would voluntarily sign up for a time-of-use rate over time.⁸³ This produces forecasts of market penetration for a given point in time based on three parameters (number of people who will eventually participate, likelihood of a non-participant deciding to participate due to the influence of a participant, and likelihood of a non-participant deciding to participate due to the influence of factors other than participants) and on the total market penetration prior to the time period being forecasted. The Bass diffusion curve assumes that only a subset of the eligible customers initially participate and curtail load (referred to as "early adopters") and that "word of mouth" recommendations from these early adopters have an influence on subsequent participation rates.

XENERGY applied the Bass curve to electric accounts in seven market segments (five residential and two non-residential representative accounts were used). Information on the number of accounts in each segment and on the average electric demand during the "peak" summer period was provided by Southern California Edison, the local utility. Three parameters of the Bass curves for each segment were estimated by the expert panel.

The output of the Bass model is an estimate of the number of accounts and the amount of load that would choose to be on a time-of-use rate each year. To forecast the load impacts of the time-of-use rate, the expert panel assumed the ratio of the peak to off-peak price would likely be about 3 to 1. That ratio resulted in the shifting of about 10%-15% of peak-period electricity usage to the off-peak period. The panel responses suggested that residential customers would be able to shift a higher percentage of their peak load than non-residential customers.

Neenan Associates HECO study

For a Western IOU, Neenan Associates (a Utilipoint company) developed estimates of the economic potential for demand and price response in light of the utility's need for resources to manage peak loads for a 3-5 year period. Demand response potential estimates were calculated for each market segment based on three customer characteristics: size (average maximum demand)⁸⁴, business type (SIC code), and rate class. This was accomplished by calculating a "peak performance index" (PPI), defined as the ratio of curtailed load to a customer's peak demand, for each market segment of customers in the ISO-NE and NYISO programs. The PPI estimates were then applied to

⁸³ The Bass Curve is commonly used to forecast the market acceptance of new concepts or existing concepts with very low market awareness.

⁸⁴ Information on the HECO customers' average maximum demands was not available. To address this, sales (kWh) data were used along with load factors (derived from calculations and expert judgment) to estimate the maximum demand (kW) of each customer.

similar market segments in the Western utility's service territory to calculate the demand response potential for each market segment. Sensitivity analyses were performed to estimate the impact of varying penetration rates on market potential. An expansion of residential device control program was recommended, along with its extension to small businesses. Time-of-use and real-time-pricing (RTP)-type rates were recommended for larger customers to build sustainable economic price response behaviors.

EPRI Study

The Electric Power Research Institute (EPRI), on behalf of the California Energy Commission (CEC), conducted an analysis to better understand customer participation in demand response tariffs and programs, and to identify and develop any "unique, non-duplicative" software tools that could facilitate the study of demand response potential (EPRI Solutions 2005).

Parts of the study involved identifying groups of customers with common characteristics (e.g. size, enabling technology, etc.) that make them good candidates for participating in demand response programs. One of the activities under this task was to estimate the amount of load reduction achievable from the customer groups. Data from in-depth interviews with energy managers of selected industrial and agricultural groups was used for this purpose. This was done by first estimating the coincident peak demand for each group, and then estimating an "upper limit" on load reduction potential from customer survey responses.⁸⁵ This estimate was then successively scaled down. First, an adjustment was made to account for the percentage of peak demand deemed to be "realistically curtailable". This was accomplished with scaling factors estimated from survey responses and experience from other demand response programs. Next, the estimates were reduced to reflect the percentage of committed load actually shed. This factor was assigned a value of 80%. Finally, the estimates were further reduced to account for expected program participation rates. The survey also collected information about customer awareness of demand response programs, decision-making process on whether to participate in demand response programs, and type and characteristics of tools that can assist energy managers in their decision-making process.

Elasticity Approach

We found only one example of a study that adopted an elasticity approach to estimating demand response market potential. Christensen Associates estimated the potential demand response effects of RTP in California using elasticities estimated from the experience of Georgia Power Company's RTP program, on which 1,600 of its large C&I customers take service (Braithwait and Armstrong, 2004).

Christensen Associates calculated elasticity estimates from the usage data of Georgia Power's RTP customers of various business types and applied them to data on similar groups of customers in California. The results were appropriately scaled to reflect the

⁸⁵ Customers were asked to apportion their load among various end uses, and then to rate each end use with respect to its curtailability. Load corresponding to the end uses that were definitely not curtailable was subtracted from the customer's peak demand.

relative size of those business types in California. It was estimated that 5,000 MW of C&I customer load could be eligible for RTP. Assuming full participation in a two-part RTP structure, aggregate load reductions of 800 MW were estimated for high hourly prices in the range of \$0.50/kWh. Customer participation was addressed in sensitivity analyses (for example, at 50% market acceptance, load response would be about 400 MW).

Appendix B. Methods for Establishing Customer Baseline Loads

This Appendix discusses methods and issues that arise in establishing a customer's baseline electricity usage. A customer baseline load (CBL) refers to the amount of electricity a customer would have consumed in the absence of a demand response event.⁸⁶ In estimating demand response market potential, CBLs are used in two contexts: (1) to estimate arc elasticities (see section 3.4.1)⁸⁷ and (2) to estimate load reductions from elasticity values (see section 3.5). CBLs are also a design feature of many demand response programs—they provide an estimate of customers' otherwise-applicable level of electricity usage against which load reductions can be measured. This provides a means to determine the level of incentives (or penalties) due to individual customers in incentive-based programs. Two-part RTP tariffs also use a CBL to determine a level of usage that is priced at a flat (or time-of-use) rate, with deviations from the CBL exposed to hourly-varying prices.

CBL definitions used by demand response programs typically rely on customers' actual load shapes on days leading up to a demand-response event day. The underlying premise is that the days just before the demand response events are most likely to characterize the level and profile of energy that customers would otherwise have used on the event day, capturing seasonal and economic forces, other than prices that drive demand. To account for weather impacts (e.g., loads may naturally be higher on event days due to high temperatures), some programs allow the customer to add an adjustment factor that accounts for the event day's temperature compared to previous days. Relying on historical data allows customers and program administrators to agree on an amount of load reduction occurring during a demand response event that can be used for settlement purposes. This can be critical for demand response programs that require customers to reduce load by a specified amount, as opposed to a specified level, and impose penalties for non-compliance. The CBL calculation procedures used in demand response programs for which we estimated elasticity values are summarized below.

NYISO Emergency Demand Response Program (EDRP) and California Critical Peak Pricing tariff

In the NYISO EDRP program, a customer's CBL is calculated based on the average daily event period usage (during similar hours as the event) for each of the most recent ten weekdays, starting two days prior to the event and excluding holidays and other EDRP event days. Low usage days, where average daily event period usage was less than 25% of the average event period usage, are also excluded. From these ten days, the five with the highest electricity usage are selected. For each hour of the event, the average usage in that hour over the five selected days is the CBL.

The CBL method used for the California Critical Peak Pricing program is almost identical to the NYISO method. The only difference is that the three highest-usage days are used in the CBL calculation, rather than five.

⁸⁶ Note that methods used to establish a CBL are premised constructions, because the level of load that would have been consumed by the customer in the absence of a demand response event is unknowable.

⁸⁷ A CBL is not necessary to estimate substitution elasticities (see section 3.4.1).

ISO-New England CBL Method

The ISO-New England CBL method uses rolling averages. Each day, a customer's CBL is updated, with the new CBL calculated by averaging the previous day's metered load (10% weight) and the previous day's CBL (90% weight). The previous day's CBL too is an average of the load and CBL from the day prior, and so on and so forth. Thus, the CBL is derived from the customer's historical load on each non-event weekday day since joining the program.

Appendix C. Programs and Tariffs Used as Data Sources

This Appendix provides a short description of each of the demand response programs and dynamic pricing tariffs included as data sources in this report, as well as references to other studies that provide more information on them.

Central and South West Two-Part RTP Tariff

We developed elasticity values for optional day-ahead hourly pricing from an evaluation of Central and South West (CSW) Utilities' (now American Electric Power) two-part RTP tariff (Boisvert et al. 2004). The CSW RTP tariff prices variations from a pre-established CBL at hourly-varying prices. The CBL is established individually for each customer, and is an hour-by-hour representation of expected consumption on the otherwise-applicable standard tariff. As CBL usage is charged at the otherwise-applicable tariff rate, it represents a hedge to the customer. Hourly prices are communicated to customers on a day-ahead basis, and any deviations in usage from the CBL are either credited or debited from the CBL usage at the hourly rate.

CSW also offered an optional program in which a customer could nominate some of the CBL for additional short-term hourly price exposure in return for a corresponding reduction in the tariff demand charge. For these participants, day-ahead prices were provisional. CSW could, within specified limits, adjust their hourly prices upward by \$0.38/kWh with only a single hour's notice, and simultaneously reduce their CBL by the amount of nominated load. Since these customers faced greater price volatility, they were expected to be more price-responsive.

Niagara Mohawk Power Company SC-3A Tariff

We developed elasticity values and market penetration rates for default-service day-ahead hourly pricing, drawing upon a case study of Niagara Mohawk Power Corporation (NMPC), now a National Grid Company. NMPC has offered hourly unbundled pricing as the default tariff for its largest customers, with peak demand greater than 2 MW, since 1998. In contrast to the CSW tariff, there is no CBL. Instead, distribution charges are unbundled from commodity to facilitate retail competition for commodity supply. All commodity usage is billed at a rate indexed to the New York Independent System Operator (NYISO)'s day-ahead wholesale market. Delivery charges are collected through a demand charges. Some customers also elected to face hourly prices in supply contracts arranged with competitive retail suppliers. See Goldman et al. (2005) for more details on the tariff design, context, and customer response to hourly pricing.

New York Independent System Operator Emergency Demand Response Program

We developed elasticity values and market penetration estimates for a short-notice, emergency demand response program, drawing from evaluations of the New York Independent System Operator (NYISO) Emergency Demand Response Program (EDRP). The EDRP provides customers an opportunity to earn the greater of \$500/MWh or the prevailing location-based marginal price (LBMP) for curtailments when NYISO calls them during system-wide or locational operating reserve shortages. This program is

voluntary; there are no consequences for enrolled participants that fail to curtail within the two hours of the request. For more information on the program and customer response, see Neenan et al. (2003).

ISO-New England Real-time Demand Response Program

Our market penetration estimates for a short-notice, emergency demand response program also draw upon results from the ISO-NE Real Time Demand Response Program. ISO-NE offers financial incentives to customers for curtailments when operating reserves are forecasted to run short. However, ISO-NE's Real-Time Demand Response (RTDR) program offers customers two advance-notice options: 30 minutes or two hours. Participants electing the 30-minute notice period, who reduce their consumption during the event, are paid the greater of the Real-Time Locational Marginal Price (LMP) applicable to their load zone or \$500/MWh. For those electing the longer notice period, a lower floor payment is set: \$350/MWh. Participants in this program are also eligible to earn installed capacity (ICAP) credits. The quantity (in MW) of a participant's ICAP credit is based on their enrolled (committed) reduction or actual performance in a reliability event. Failure to reduce load during an event results in the forfeiture of ICAP credit earned for the month the event occurred. In addition, the participant's ICAP credit in the months following the reliability event is de-rated accordingly. For more information on this demand response program and customer response to it, see RLW Analytics and Neenan Associates (2003, 2004 and 2005).

ISO-New England Real-time Price Response Program

We developed elasticity values and market penetration estimates for an ISO price response event program, drawing upon evaluations of the ISO-NE Real-Time Price Response (RTPR) program. The RTPR provides financial incentives to participating retail customers for voluntary load reductions when the Real-Time LMP is expected to be greater than or equal to \$100/MWh during the hours of 7:00 a.m. to 6:00 p.m. on non-holiday weekdays.⁸⁸ Once the price event is declared, ISO-NE is authorized to make payments for any load that is curtailed during the entire 11-hour period. Participating customers are paid the greater of \$100/MWh or the Real-Time LMP in their Load Zone for voluntary load reductions during price events. For more information, see RLW Analytics and Neenan Associates (2003, 2004, and 2005).

California Utilities' Critical Peak Pricing Program

We developed elasticity values and market penetration estimates for a critical-peak pricing tariff targeted at commercial and industrial customers, drawing upon evaluation results of a critical-peak pricing tariff implemented by California's three investor-owned utilities (see Quantum Consulting and Summit Blue Consulting 2006 for more details). The tariff is offered to C&I customers with peak demands of 200 kW and above for Pacific Gas & Electric and Southern California Edison and 100 kW and above for San Diego Gas & Electric. Critical-peak events can be declared for a number of reasons (e.g.

⁸⁸ ISO-NE opens the eligibility period in a Load Zone when actual Day-Ahead Locational Marginal Prices (LMP) or Real-Time LMP as forecasted by a Resource Adequacy Analysis for that Load Zone equals or exceeds \$100/MWh during the eligible hours (7:00 a.m. to 6:00 p.m.).

temperature, system constraints, utility discretion, etc.). The events are pre-specified to apply for the hours of 12 noon to 6:00 p.m. Usage in the first three hours is priced at roughly three times the otherwise applicable tariff (OAT) rate, and the subsequent three hours are priced between five and ten times the OAT. Customers receive day-ahead notice of impending events. For more details see Quantum Consulting and Summit Blue Consulting (2004 and 2006).

Appendix D. Factors Found to Influence Demand Response Program Participation

In this Appendix, we summarize the findings of research into drivers for customer participation in the demand response programs used as data sources in this study.

Customer-specific Factors that Influence Participation Rates

Three evaluation studies examined customer-specific factors that may influence participation rates in the following demand response options: Niagara Mohawk Power Company (NMPC)'s default hourly-pricing tariff, the California utilities' critical-peak pricing tariffs, and the New York Independent System Operator (NYISO) Emergency Demand Response Program (EDRP). In these evaluations, information about customer-specific characteristics was collected through in-depth customer surveys and interviews of a sample of eligible customers. The findings discussed here are statistically robust.

Based on a logistic model developed for customer participation in NMPC's default hourly pricing tariff, Goldman et al. (2004) found that:

- customers located in the Capital region (where prices were higher than in other regions) were four times more likely to stay on default-service hourly pricing than customers in other regions;
- industrial customers were four times, and government/education customers were three times, more likely to remain on the default rate than commercial/retail and healthcare customers; and
- customers with summer-peaking electricity usage were 4.5 times more likely to opt out of the default hourly-pricing tariff than winter-peaking customers.

Quantum Consulting Inc. and Summit Blue Consulting LLC's (2004 and 2005) evaluations of California's critical-peak pricing program also used logistic models to identify important customer-specific characteristics that drive participation rates. Compared to non-participants, participants in the California demand response programs were found to:

- be more likely to have participated in other demand response programs;
- closely monitor electricity markets and prices;
- report that their energy costs comprise over 10% of their total annual operating costs; and
- hold an optimistic view of the adequacy of California's power supply.

Non-participants reported an inability to reduce peak demand more often than participants. They were also less likely than participants to engage in batch processing.

Two evaluations of NYISO's demand response programs have yielded insights into customer decisions to participate in demand response programs (Neenan et al. 2002 and 2003). Based on logistic analyses, these studies reported that:

- customers that have prior experience with load management programs were more likely to participate in demand response programs;

- educating customers on how to reduce load was likely to increase participation by a factor of two;
- customers with access to real-time load information were twelve times more likely to participate than customers without this information; and
- the provision of technical and financial assistance (e.g., through NYSERDA programs) also increased the odds of customer participation in EDRP.

The NYISO evaluations also found that several customer characteristics were important predictors of customer participation:

- the odds of manufacturing customers participating in an emergency program were about six times higher than for other customers;
- customers whose peak electricity usage occurs during the afternoon were 3.6 times as likely to participate in NYISO’s EDRP than other customers;
- customers with multiple production shifts (i.e., more flexible operating practices) were twice as likely to participate than customers with just one shift; and
- the odds of customers with on-site generation participating in an emergency program were over three times higher than other customers.

Year-to-Year Participation Trends

As discussed in section 3.3, participation in demand response programs can change each year as some customers drop out and others enroll. Most demand response programs require a one-year commitment, and customers must re-enroll on an annual basis. Table D-1 illustrates how participation can change over time. Enrollment statistics are shown for two representative years, along with “churn rates”—the percentage of customers dropping out, signing up, and switching to or from alternative programs—for ISO-NE and NYISO demand response programs.

Table D-1. Churn Rates for ISO-NE and NYISO Demand Response Programs

Program	Reference-year ¹ enrollment ²	Changes in Enrollment (churn rates)				New enrollment ²
		dropouts	new enrollees	switched to other programs	switched from other programs	
ISO-NE Emergency DR Programs	91	31%	56%	9%	9%	114
ISO-NE Price Response Program	332	14%	24%	0.6%	0.6%	367
NYISO EDRP and ICAP-SCR	1761	33%	20%	N/A	2%	1536

¹ Reference year is 2003 for the ISO-NE programs, and 2002 for the NYISO programs.

² Enrollment is in terms of number of customer accounts.

For both of the ISO-NE programs, total enrollment increased from 2003 to 2004, and for the NYISO programs, overall participation declined between 2002 and 2003. However, the overall statistics hide underlying churn rates. ISO-NE’s emergency program experienced much higher volumes of customers leaving and entering the program than the price response program. For the NYISO emergency programs, although a significant

number of new customers enrolled in the program, an even higher dropout rate was responsible for the overall decline in enrollment.

Unfortunately, insufficient data were available to assess churn rates over a longer period. Moreover, a number of changes to the program designs may have impacted the observed rates. Therefore, it is difficult to draw any conclusions from these results.